MIT Joint Program on the Science and Policy of Global Change

Improving the Refining Sector in EPPA

Frederic Choumert, Sergey Paltsev and John Reilly

Technical Note No. 9
July 2006

The MIT Joint Program on the Science and Policy of Global Change is an organization for research, independent policy analysis, and public education in global environmental change. It seeks to provide leadership in understanding scientific, economic, and ecological aspects of this difficult issue, and combining them into policy assessments that serve the needs of ongoing national and international discussions. To this end, the Program brings together an interdisciplinary group from two established research centers at MIT: the Center for Global Change Science (CGCS) and the Center for Energy and Environmental Policy Research (CEEPR). These two centers bridge many key areas of the needed intellectual work, and additional essential areas are covered by other MIT departments, by collaboration with the Ecosystems Center of the Marine Biology Laboratory (MBL) at Woods Hole, and by short- and long-term visitors to the Program. The Program involves sponsorship and active participation by industry, government, and non-profit organizations.

To inform processes of policy development and implementation, climate change research needs to focus on improving the prediction of those variables that are most relevant to economic, social, and environmental effects. In turn, the greenhouse gas and atmospheric aerosol assumptions underlying climate analysis need to be related to the economic, technological, and political forces that drive emissions, and to the results of international agreements and mitigation. Further, assessments of possible societal and ecosystem impacts, and analysis of mitigation strategies, need to be based on realistic evaluation of the uncertainties of climate science.

The Program's Technical Notes series is intended to document technical research details for our own use, and also for other researchers who may wish to recreate or update the work. Further information is available by request to the Program Office at the numbers listed below.

Henry D. Jacoby and Ronald G. Prinn,
Program Co-Directors

For more information, please contact the Joint Program Office

Postal Address: Joint Program on the Science and Policy of Global Change
77 Massachusetts Avenue
MIT E40-428
Cambridge MA 02139-4307 (USA)

Location: One Amherst Street, Cambridge
Building E40, Room 428
Massachusetts Institute of Technology

Access: Phone: (617) 253-7492
Fax: (617) 253-9845
E-mail: globalchange@mit.edu
Web site: http://mit.edu/globalchange/

Improving the Refining Sector in EPPA

Frederic Choumert[†], Sergey Paltsev and John Reilly

Abstract

The MIT Emissions Prediction and Policy Analysis (EPPA) model is a recursive-dynamic multi-regional general equilibrium model of the world economy, which is built on the GTAP5 dataset and additional data for the greenhouse gas and urban gas emissions. The GTAP5 dataset aggregates all the different types of petroleum products, from transportation fuels to refinery residues, in the same "refined oil" commodity. We augment the GTAP supply, demand, and trade data in order to disaggregate the refined oil commodity into six different categories of petroleum products, each with its specific uses and associated emission factors. We then expand the EPPA model accordingly, and improve its representation of the oil industry by introducing new upstream and downstream oil technologies and taking into account the changes in the crude mix. This work opens the door to future in-depth analyses of how supply and demand for refined products could be affected by climate policy.

Contents

[†] Visiting scholar for TOTAL at MIT's Joint Program on the Science and Policy of Global Change

Overview

The aim of this Technical Note is to describe how we improve the representation of the supply and demand for petroleum products in MIT's Emission Prediction and Policy Analysis (EPPA) model, for purposes of studying the long-term impact of carbon constraints on the downstream oil industry. The EPPA model is a recursive-dynamic multi-regional general equilibrium model of the world economy (Paltsev et al., 2005), which is built on the GTAP5 dataset (Dimaranan and McDougall, 2002) and additional data for greenhouse gas (CO_2, CH_4, N_2O, HFCs, PFCs, and SF_6) and urban gas emissions (SO_2, NO_x, CO, black carbon, volatile organic compounds, etc.). The energy commodities represented in the GTAP5 dataset – and subsequently in EPPA - are crude oil, natural gas, coal, electricity, and a single refined oil commodity encompassing all the different petroleum products from crude oil refining. As physical properties (energy content, carbon content or other emission factors), final uses (transportation fuels, heating oils, petrochemical feedstocks, etc.), and production costs can greatly vary among the different refined products, disaggregating EPPA's refined oil commodity into several categories of refined products is a necessary step towards a more accurate picture of the downstream oil industry, allowing better analyses of climate and environmental policy impacts on the sector. This disaggregation work leads us to modify the structure of energy supply and demand in EPPA, and complete the model by adding new backstop technologies, for both downstream and upstream oil industries. In the following, we refer to this modified version of EPPA as "EPPA–ROIL".

The note is organized as follows: the first section of this paper outlines the general objectives of our work and the methodology used. The second section describes the different steps to disaggregate both GTAP physical and value flows. The third section details the improved representation of petroleum products' economics: trade specifications and energy demand are adapted to the different categories of refined products, and the refining sector's production function is revised to allow multiple outputs and better reproduce the constraints that apply to refining processes. An essential part of our work consists in modeling residue upgrading technologies, to allow further processing of heavy refinery residues into synthetic gas, electricity, or transportation fuels in our model. A fourth section explains how we achieve a better portrayal of the constraints weighing on the refining industry by representing the change in the crude slate. The final section lists the caveats related to the changes made to the model, and provides a few ideas for future improvements.

1. OBJECTIVES AND METHODOLOGY

Our work to improve EPPA's representation of the downstream oil industry can be defined in two steps:

- **Disaggregating data**: the EPPA model's underlying dataset was expanded with different categories of refined products. The model's supply and demand structure is then adapted to take into account the disaggregated refined products.
- **Modeling**: new technologies were added to improve the representation of the downstream oil industry

This section outlines the objectives and the methodology used in these two steps of our work. **Figure 1** summarizes the modifications in the EPPA-ROIL model compared to the original EPPA model version 4.

EPPA4	***Objectives***	**EPPA-ROIL**
Downstream oil: Refining sector has a single refined product output (ROIL)	*Represent multiple refined products*	**Downstream oil:** Refining sector is a multi-output constant elasticity of transformation (CET) production function, producing refinery gases, gasoline, diesel, heavy fuel oil, petroleum coke, and other products
	Represent the possibility to upgrade heavy fuel oil	• Residue upgrading technology can process heavy fuel oil into transportation fuels • Refinery residues can be gasified to produce syngas without CO_2 capture or electricity with CO_2 capture
Second generation biofuels are represented as a backstop technology producing a perfect substitute for refined oil	*Represent different types of biofuels*	The biofuels production sector is a multi-output, producing perfect substitutes for gasoline and diesel
Upstream oil: Conventional oil and extra-heavy oils are aggregated within the "OIL" commodity	*Represent explicitly production of non-conventional oils*	**Upstream oil :** • Non-conventional oil reserves separated from conventional oil reserves • Separate function for extra-heavy oil production in Canada and Latin America • Extra-heavy oil upgrading production function: bitumen can be processed into light synthetic crude

Figure 1. From EPPA4 to EPPA-ROIL.

1.1 Expanding the dataset

Refineries process crude oil into numerous value fractions, ranging from light products such as ethane, propane, or butane, to heavy products such as residual fuel oil or bitumen. Most petroleum products are used as fuels, especially for transportation: generally, gasoline, diesel or liquefied petroleum gases (LPG) represent more than half of total refinery output. LPG, fuel oil, or petroleum coke can be used in industrial processes or for heating purposes. Petroleum products can also serve different, non-combustion purposes: naphtha is a feedstock for the petrochemicals industry where it can be cracked to produce ethylene, propylene, etc.; lubricants can be used to reduce friction between bearing surfaces; bitumens are used for road coating.

Our goal in modifying EPPA is to capture the differences in several broad classes of these products, while introducing a minimum of complexity to the model. First, we add three categories of refined products, to represent the three major types of transportation fuels: LPG, gasoline, and diesel oil. LPG is part of a broader category, "RGAS", which comprises gas-related liquids and all refinery gases (e.g. ethane, fuel gas). The "Gasoline" (GSLN) category comprises motor gasoline for vehicles, but also similar fractions such as aviation gasoline and gasoline-type jet fuel. The "Diesel" (DISL) category encompasses automotive diesel, kerosene-type jet fuel, and other kerosenes (which are used as transportation fuels or as heating oil). We also need to introduce categories for refinery residues such as residual fuel oil and petroleum coke: we add two commodities, Heavy Fuel Oil (HFOL) and Petroleum Coke (COKE). Our HFOL commodity will generally represent refinery residues that can still be upgraded to lighter fuels (via conversion or deep conversion processes). The COKE commodity will represent the final byproducts of residue upgrading. Indeed, heavy fuel oil typically is a blend of several heavy fractions coming from different distillation units: atmospheric residues, vacuum residues, vacuum gas oil, etc. It still contains high-value fractions that can in part be separated economically with the help of upgrading units. Conversely, petroleum coke is a coal-like byproduct of residue thermal cracking: most high-value fractions have already been extracted. Finally, the category "Other petroleum products" includes all the refined products not destined for combustion. This allows us to fully distinguish the different types of petroleum products in terms of their emissions of various pollutants: combusted products release several air pollutants and greenhouse gases, such as CO_2, CH_4, CO, black carbon, VOCs[1] and SO_2 etc, whereas bitumen, lubricants, waxes, are less emissive of air pollutants, and mostly emit VOCs, as the hydrocarbon chains and impurities they contain are not oxidized in a combustion reaction[2].

The flows of energy goods in EPPA are based on the GTAP5 dataset (Dimaranan and McDougall, 2002). They are measured in both value and physical units: for example, refined oil flows are measured in quantity (Exajoules[3]) and value (the unit is 10 billion dollars in EPPA). The first logical step in expanding the dataset is to disaggregate the physical flows of refined oil (section 2.2). We proceed by using International Energy Agency databases (IEA, 2005a and 2005b) to calculate the shares of every refined product in refined oil demand and trade flows, and we then apply these shares to EPPA's physical flows of refined oil. The private transport energy consumption data and the bilateral trade data by product are not available for all regions in IEA databases or national studies, so several assumptions must be made (sections 2.2.1 and 2.2.4). Once the physical flows are disaggregated, we use both IEA price data (IEA, 2005b) and Energy Information Administration data (EIA, 2004) to estimate regional and sectoral prices for our different categories of refined products (section 2.3.1). Multiplying these refined product prices by physical flows gives us the shares of every refined product in refined oil demand,

---

[1] Volatile organic compound.

[2] CO_2 and other pollutants can be emitted by naphtha cracking processes in the petrochemicals industry: the handling of this exception is described in section 2.6.

[3] 1 Exajoule (EJ) = 10^{18} Joules

supply, and bilateral trade flows, which we then apply to the refined oil value flows in EPPA in order to obtain disaggregated value flows. When one uses data from outside the national income and product accounts on which the Social Accounting Matrix (SAM) data of GTAP is based it is then likely that the resulting expanded input –output and SAM data are unbalanced e.g. the value of domestic production of one refined product is not equal to the value of domestic consumption plus net exports (even though it is true for the aggregated refined oil commodity). We solve a minimization problem to find balanced flows as close as possible to our original estimates, a standard practice in developing a balanced SAM (section 2.3.3).

1.2 Modeling an improved representation of the downstream oil industry

We adapt the model to the new expanded dataset with disaggregated refined products (sections 3.1 to 3.4), which enables us to improve the representation of supply, demand, and trade for refined products. In doing so, we introduce multi-output production functions for the refining sector (section 3.2.1) and the biofuels backstop technology (section 3.2.1).

Adding new technologies to EPPA's oil sectors enables us to capture the constraints which weigh on the refining industry and are related to the changing of both the product demand and the crude mix. The modeling of different upgrading technologies enables us to represent the possibility of further processing of heavy refinery residues into synthetic gas, electricity or transportation fuels, at a higher cost and, in most cases, with increased emissions of pollutants at the plant. Modifications to the model in this regard include additions of:

- heavy fuel oil and coke gasification production functions, which produce a perfect substitute for natural gas and are based on the existing coal gasification production function (section 3.5.1);
- production functions for heavy fuel oil and coke integrated gasification combined cycle with carbon capture and storage (IGCAP), which produce low-carbon electricity and are based on the existing coal IGCAP (section 3.5.2);
- a production function for a residue conversion technology, transforming heavy fuel oil into lighter transportation fuels (section3.5.3).

Introducing new upstream oil technologies for non-conventional oils enables us to capture the additional costs and emissions related to non-conventional crude production and upgrading. Modifications of EPPA's oil sector in this regard include:

- separating the production of conventional oil from that of oil sands and extra-heavy oils (sections 4.1 and 4.2);
- separately identifying upgrading production processes for these heavier crudes (section 4.2);
- addressing the regional effects of changes in crude quality on the mix of refining outputs (section 4.3).

We adopt the methodology described in McFarland et al (2004) to model a backstop technology in a top-down model using bottom-up information (section 3.5): the new technology's energy efficiency, relative factor shares, and mark-up factor over the conventional technology are first estimated using engineering studies. The input shares are then calibrated such that the technology's energy efficiency in the model is consistent with the previous estimate. The engineering data used comes from previous work by the MIT Joint Program on the Science and Policy of Global Change (McFarland et al., 2004; Paltsev et al., 2005), various publicly available industry studies (e.g. National Energy Technology Laboratory, 2005; Hanou, 2004; CONCAWE, 1999; Demailly, 2005; Philips and Liu, 2002; Canada Natural Energy Board, 2004; Natural Resources Canada, Petroleum Resources Branch, 2005; Crandall, 2002; Cupcic, 2003), and private conversations with industry experts.

2. BREAKING UP THE REFINED OIL COMMODITY IN EPPA'S SOCIAL ACCOUNTING MATRIX

As described in Paltsev et al., 2005, the EPPA model version 4 (EPPA4) is built on the GTAP5 dataset (Dimaranan and McDougall, 2002), which aggregates all refined products in a single refined oil commodity (the "ROIL" commodity in the EPPA model). This section describes how we disaggregate this refined oil commodity in EPPA's GTAP5-derived Social Accounting Matrix.

2.1 The six different categories of refined products

As explained in section 1.1, we introduce six different categories of refined products:

- Refinery gases (labeled "RGAS" in EPPA-ROIL)
- Gasoline ("GSLN")
- Diesel oil ("DISL")
- Heavy fuel oil ("HFOL")
- Petroleum coke ("COKE")
- Other petroleum products ("OTHP")

The correspondence between these six categories and the International Energy Agency databases (IEA, 2005a and 2005b) which we use for the disaggregation of the refined oil commodity is given in **Table 1**.

2.2 Disaggregating the physical flows

In EPPA, all inputs and outputs are measured in value terms (i.e. prices times quantities). For energy commodities, the value flows are linked to balanced physical flows in energy units (Paltsev et al., 2005), in order to keep track of the depletion of resources, emissions of pollutants, etc. As detailed physical data are available in the International Energy Agency's Extended Energy Statistics (IEA, 2005a), the first step to disaggregating the refined oil commodity in EPPA is to break up the physical flows for demand, supply, and international trade.

2.2.1 Household own-supplied transport demand for refined products

Demand for refined products by households is divided into two categories: a demand for vehicle fuels (LPG, gasoline, diesel oil) for private cars, and a residential demand, mostly for heating and cooking.

Table 1. Definition of the six categories of refined products in EPPA.

IEA Product Name	EPPA–ROIL Category	Name of Commodity in EPPA–ROIL
Natural Gas Liquids	REFINERY GASES	RGAS
Refinery Gas	REFINERY GASES	RGAS
Ethane	REFINERY GASES	RGAS
Liquefied Petroleum Gases (LPG)	REFINERY GASES	RGAS
Motor Gasoline	GASOLINE	GSLN
Aviation Gasoline	GASOLINE	GSLN
Gasoline type Jet Fuel	GASOLINE	GSLN
Kerosene type Jet Fuel	DIESEL OIL	DISL
Other Kerosene	DIESEL OIL	DISL
Gas/Diesel Oil	DIESEL OIL	DISL
Refinery Feedstocks[4]	HEAVY FUEL OIL	HFOL
Heavy Fuel Oil	HEAVY FUEL OIL	HFOL
Petroleum Coke	PETROLEUM COKE	COKE
Naphtha	OTHER PETROLEUM PRODUCTS	OTHP
White Spirit	OTHER PETROLEUM PRODUCTS	OTHP
Lubricants	OTHER PETROLEUM PRODUCTS	OTHP
Bitumen	OTHER PETROLEUM PRODUCTS	OTHP
Paraffin Waxes	OTHER PETROLEUM PRODUCTS	OTHP
Other Petroleum Products	OTHER PETROLEUM PRODUCTS	OTHP

The IEA Extended Energy Statistics specifies energy consumption for transport by fuel and by mode (air, water, road, rail, and pipeline). However, unlike in EPPA4, no difference is made between commercial transport (freight, passenger transport, etc.) and household own-supplied transport (private automobiles[5]).

With typical mileage by engine type (Direction des Affaires Economiques et Internationales/ Service Economique et Statistiques – Institut National de la Statistique et des Etudes Economiques, 2004) and average on-road fuel use per unit distance (World Business Council on Sustainable Development, 2005) by engine type[6] (**Table 2**), and estimates for the stock (**Table 3**), we evaluate the physical shares of LPG, gasoline, and diesel consumption for each EPPA region (**Table 4**).

In order to stay consistent with previous work on the EPPA's household transportation sector (Paltsev et al., 2004), we start by calculating $T\_FS_{f,r}$, the household expenditure on fuel f for own-supplied transportation, as a share of total household expenditures on refined products for own-supplied transportation. This share is calculated using the physical shares (Table 4) and estimates of relative fuel prices (after IEA, 2005b). In region r, household expenditure on fuel f for private transport is then given by:

$$T\_FUEL_{f,r} = OS_r \times TOS_r \times T\_FS_{f,r}$$

[4] In IEA (2005a), refinery feedstocks are defined as "processed oil destined for further processing" (e.g. straight run fuel oil or vacuum gas oil).

[5] Including cars, light trucks, and motorcycles.

[6] European diesel vehicles are generally more expensive than gasoline vehicles, but boast a better fuel economy. Consequently, diesel vehicles are profitable when driven more than their gasoline counterparts, hence the generally higher mileage observed for these vehicles.

with:

- OS_r being the share of household expenditures on refined oil products for own-supplied transportation in the total household expenditure on all refined oil products (Paltsev et al., 2004);
- TOS_r being the total household expenditure on all refined products (Paltsev et al., 2004).

The physical demand of fuel f for household own-supplied transportation, $PT\_FUEL_{f,r}$, is finally obtained by dividing the expenditure $T\_FUEL_{f,r}$ by the fuel price.

Table 2. Relative mileage and fuel use by engine type in 1997 (gasoline = 1.0).

	Relative mileage	**Relative fuel use** (liters / 100 km basis)
LPG	1	1.05[7]
Gasoline	1	1.00
Diesel	1.7	0.82

Table 3. Percentage of vehicles in total stock in 1997, by engine type*.

	USA**	**CAN**	**MEX**	**JPN**†	**ANZ**‡	**EUR**◊	**EET**	**FSU**
Gasoline	99.40	98.50	98.90	89.20	96.00	81.00	91.50	91.50
Diesel	0.50	1.00	1.00	10.40	2.80	17.50	8.00	8.00
LPG	0.10	0.50	0.10	0.40	1.20	1.50	0.50	0.50
	ASI	**CHN**	**IND**	**IDZ**	**AFR**	**MES**	**LAM**	**ROW**
Gasoline	90.00	98.99	55.00	93.00	98.50	98.90	97.70	93.00
Diesel	9.70	1.00	45.00	6.50	1.00	1.00	2.00	6.50
LPG	0.30	0.01	0.00	0.50	0.50	0.10	0.30	0.50

* In "car-equivalents" for Asian countries, especially India, where motorcycles remain the predominant form of private motorized transport. Roughly, we assume that five motorcycles is one car equivalent.

** Assumption derived from data in Energy Information Administration (1994).

† Japan Automobile Manufacturers Association (2004).

‡ Assumption derived from Australian Bureau of Transport and Regional Economics (2005).

◊ Assumption derived from: Direction des Affaires Economiques et Internationales/Service Economique et Statistiques – Institut National de la Statistique et des Etudes Economiques (2004); European Commission (2003); Bensaid & Bernard (2005).

Table 4. Calculated physical shares of fuel consumption in 1997, per region (%).

	USA	**CAN**	**MEX**	**JPN**	**ANZ**	**EUR**	**EET**	**FSU**
Gasoline	99.10	98.00	98.40	84.10	94.60	74.20	87.70	87.70
Diesel	0.80	1.60	1.50	15.60	4.40	24.70	12.00	11.90
LPG	0.10	0.40	0.10	0.30	1.00	1.10	0.30	0.40
	ASI	**CHN**	**IND**	**IDZ**	**AFR**	**MES**	**LAM**	**ROW**
Gasoline	85.50	98.50	44.20	89.90	98.00	98.40	96.70	89.90
Diesel	14.30	1.50	55.80	9.70	1.50	1.50	3.10	9.70
LPG	0.20	0.001	0.001	0.40	0.50	0.10	0.20	0.40

[7] Even though LPG vehicles' fuel efficiency is about the same as gasoline vehicles', its measure on a liters-per-100km basis is lower than that of gasoline vehicles, because of LPG's lower density: a liter of LPG holds less energy than a liter of gasoline.

2.2.2 Residential demand

The methodology is the same for household residential demand. We use IEA data (IEA, 2005a) on residential consumption of refined products in the different regions of EPPA to calculate $R\_FS_{f,r}$, the household expenditure on fuel f for residential use as a share of total household expenditures on refined products for residential use. Then:

$$R\_FUEL_{f,r} = (1 - OS_r) \times TOS_r \times R\_FS_{f,r}$$

The physical demand of fuel f for household residential consumption, $RT\_FUEL_{f,r}$, is finally obtained by dividing the expenditure $R\_FUEL_{f,r}$ by estimates for residential fuel prices.

Finally, for each region, the household own-supplied transport and the residential refined product demand are calibrated so that they sum up to *efd*("*ROIL*", *region*), which is the final demand for the refined oil commodity, in physical terms, given in GTAP5.

2.2.3 Production sectors demand for refined products

EPPA's production sectors except transport and services

For all EPPA sectors except TRAN (commercial transport) and SERV (services[8]), it is possible to use IEA data directly to determine the share of every refined product in *eind*("*ROIL*", *sector, region*), the total refined product consumption of a given sector[9] as given in GTAP5.

Commercial transport

The IEA data on transport does not separate consumption by private automobiles from that of commercial transport[10], unlike in the EPPA model. To calculate the share of the different refined fuels in total refined product consumption by the commercial transport sector, we must subtract the household own-supplied transport consumption of a given fuel f from, the total transport consumption of fuel f as in IEA statistics ($IEA\_TRAN_{f,r}$, for fuel f in region r).

With the disaggregated household transport data (section 2.2.1) as well as EPPA data on commercial transport refined product consumption, we can calculate HH_TRANSH_r, the regional share of household own-supplied transport refined product consumption in the total transport refined product consumption, as well as $PT\_FS_{f,r}$, the physical share of fuel f consumption in household own-supplied transport refined product consumption. For refined product f, the household own-supplied transport component, $HH\_TRAN_{f,r}$, of the IEA data on transport consumption of refined product f is:

$$HH\_TRAN_{f,r} = (HH\_TRANSH_r \times \sum_f IEA\_TRAN_{f,r}) \times PT\_FS_{f,r}$$

Services

The services sector (SERV) as defined in EPPA does not appear explicitly in the IEA databases. Refined oil consumption by the services is mostly for office heating, but perhaps also partly for transport (company-owned vehicles for salespeople, etc.). Given the absence of data on this sector, we use it as a residual to eliminate differences in regional fuel consumption between IEA and our newly disaggregated EPPA data.

---

[8] Banks, insurance companies, etc.

[9] See Appendix 1, Table A1.A, for the relationship between IEA and EPPA sectors.

[10] Freight transport and passenger transport (air, rail, road, water): all transport except private automobiles.

2.2.4 Imports and Exports

The IEA Extended Energy Statistics provides us with data on imports and exports of refined products for a large number of countries. Generally, to determine the total imports and exports of refined products for a given region of EPPA, we sum up the values of imports and exports over all the countries belonging to that region. For multi-country regions such as Europe or Asia with important internal trade, we use the IEA Oil Imports and Oil Exports tables (IEA, 2005b) for OECD countries, which specify the bilateral trade flows of refined products. Using this data, we can determine the amount of internal trade in some of EPPA's multi-country regions (EUR, ANZ), and deduct it from the total exports and imports of these regions. For non-OECD regions, complete bilateral trade data was not available. IEA data is not balanced, "due to time differences in recording imports and exports, (…) differences in product classifications" (IEA, 2005a): therefore, we recalibrate the data in order to balance globally the imports and exports of every product, minimizing the distance to the original data.

2.2.5 Production

To ensure overall regional market clearance for the newly added petroleum products, the output of the refining sector is deduced from the previously disaggregated physical flows of demand, imports and exports, by the following equation:

Output(Product f, Region r) = Net Exports(Product f, Region r) + Domestic Demand(Product f, Region r)

We compare our physical flows for consistency with IEA data (IEA, 2005a) in **Table 5**. Differences come from the fact that IEA data is not balanced, and includes a "Statistical differences" variable (see Appendix 1, Table A1.A) to correct for certain accounting problems.

Table 5. Comparison of refining production levels (Exajoules[11]) between IEA and EPPA–ROIL (EPPA with disaggregated refined products).

	RGAS		GSLN		DISL		HFOL		COKE		OTHP	
	IEA	**EPPA**	**IEA**	**EPPA**	**IEA**	**EPPA**	**IEA**	**EPPA**	**IEA**	**EPPA**	**IEA**	**EPPA**
USA	7.22	7.08	14.68	15.03	11.39	10.84	1.51	1.70	1.28	1.41	2.30	2.69
CAN	1.45	1.43	1.44	1.35	1.37	1.39	0.17	0.29	0.05	0.10	0.31	0.40
MEX	1.14	1.01	0.78	0.86	0.69	0.71	0.87	1.00	0.04	0.04	0.13	0.13
JPN	0.92	0.76	2.10	1.77	3.61	4.09	1.67	1.67	0.00	0.02	0.67	1.08
ANZ	0.36	0.49	0.65	0.67	0.66	0.80	0.02	0.09	0.00	0.02	0.15	0.13
EUR	2.66	2.54	6.09	6.44	12.54	12.08	3.85	4.26	0.13	0.23	2.60	3.18
EET	0.21	0.17	0.46	0.51	0.70	0.87	0.33	0.45	0.01	0.02	0.33	0.35
FSU	0.92	0.87	1.90	1.73	3.09	3.27	3.42	3.35	0.01	0.03	0.51	0.72
ASI	0.84	0.83	1.40	1.43	4.23	5.13	2.62	3.28	0.00	0.01	1.63	1.68
CHN	0.87	0.58	1.65	1.51	1.60	2.35	0.82	0.97	0.14	0.14	1.33	1.34
IND	0.37	0.37	0.31	0.22	1.38	1.45	0.33	0.54	0.01	0.01	0.41	0.47
IDZ	0.39	0.48	0.37	0.37	0.89	0.85	0.43	0.50	0.00	0.00	0.12	0.10
AFR	1.70	2.03	0.87	0.92	1.93	2.15	1.32	1.53	0.00	0.00	0.93	0.62
MES	4.23	4.19	1.32	1.39	4.86	4.98	3.10	3.58	0.00	0.00	1.51	1.71
LAM	1.54	1.24	2.24	2.34	3.33	3.48	1.93	2.29	0.10	0.14	0.92	0.92
ROW	0.26	0.15	0.41	0.30	0.85	0.57	0.64	0.48	0.00	0.00	0.20	0.20

[11] 1 Exajoule (EJ) = 10^{18} Joules

2.3 Disaggregating the value flows

2.3.1 Price assumptions

Having disaggregated all the physical flows of refined products, we need to determine all regional and sectoral prices in order to convert these to value flows. Price data for the different refined products in the US, or worldwide prices of gasoline, diesel or heavy fuel oil can be found in the Annual Energy Review for year 2003 (US Department of Energy, Energy Information Administration, 2004), or the IEA Oil Information database (IEA, 2005b). However, regional and sectoral price data on LPG, petroleum coke, or other refined products such as bitumen, lubricants, is much harder to find. In this section, we briefly describe the assumptions we use to establish a table for refined product prices among sectors and regions (Appendix 1, Table A1.C). For the US, we mostly use the EIA price data (EIA, 2004). For other countries, we use the IEA data, calibrated by multiplying it by the EIA vs. IEA price ratio for the US.

LPG and gasoline

The industrial sector's gasoline consumption as reported by the IEA is most probably used for transport. For example, in the electric sector, consumption of gasoline can be energy used by the utility company's maintenance vehicles. Therefore, we assume the gasoline price is the same for all the EPPA sectors, equal to the price given by the IEA Oil Information Database (IEA, 2005b). Since we generally use the more precise DOE prices for the US, we calibrate all IEA prices to the DOE/EIA US price ratio. LPG prices are difficult to determine, as there is no real global market for LPG, unlike for gasoline or diesel. LPG is used partly in transport, but mostly as a heating fuel. We assume that for all sectors, the LPG 1997 price is a ratio of the gasoline price, which we estimate at 85%, based on the US DOE price data.

Diesel oil, jet fuel and heating oil

The "diesel" category comprises diesel oil (automotive or marine), jet fuel, and heating oil, three products whose prices can differ significantly. Household own-supplied transport uses automotive diesel, so the diesel price in that sector is straightforward. Residential consumption of diesel is exclusively heating oil, so the price for that sector is the heating oil price, typically much lower than the automotive diesel price. For commercial transport, the diesel fuel price is set as a weighted average of the prices of diesel oil (automotive diesel for road transport and marine diesel for maritime transport) and jet fuel[12] (air transport). For all other sectors, the diesel price is set as a weighted average of diesel oil and heating oil, depending on the sector's activity: for example, the diesel consumption of the SERV sector is mostly heating oil, so a higher weight is given to the heating oil price.

Heavy fuel oil

IEA data provides us with prices for High Sulfur Heavy Fuel Oil and Low Sulfur Heavy Fuel Oil. We assume the heavy fuel oil price is an average of these two grades.

---

[12] Typically, jet fuel is more expensive than automotive diesel, or marine diesel.

Petroleum coke

Petroleum coke price is difficult to establish at a national, let alone regional level, as the size of its markets is generally very small compared with other refined products. Because petroleum coke mostly competes with coal as a fuel[13] for electric power plants or cement factories, its price is often linked to the coal price. By observing historical data on coke and coal delivery price to US utilities (Hanou, 2004), we assume the petroleum coke price is 60% of the coal price. In EPPA, the price of coal in 1997 is around $1.0-1.5 per MMBtu, so the 1997 petroleum coke price is set at around $0.6-0.9 per MMBtu, with slight variations across sectors and regions: the price is on the high end of that range in Europe, where demand for petroleum coke exceeds local production, but lower in the US or Latin America, which both have petroleum coke surpluses.

Other petroleum products

Our "other petroleum products" category comprises a wide variety of products, from the high value naphtha fraction, whose price is often closely related to gasoline's[14], to the lower value bitumen or waxes. Thus, we set the price to an intermediate level between gasoline and the bitumen.

Prices across regions

In the IEA databases (IEA, 2005b), the price of refined products is not available for all EPPA regions. Therefore, the following assumptions are made:

- the ANZ (Australia-New Zealand) prices are taken from Australia or New Zealand, or an average when both values are available
- the EUR (EU-15, Norway, Switzerland, and Iceland) prices are weighted averages of the largest European countries
- the EET (Eastern Europe) prices are based on data from the Czech Republic, Poland, the Slovak Republic and Hungary
- the ASI (Southeast Asia) prices are based on South Korea
- the AFR (Africa) prices are based on South Africa
- the LAM (Latin America) prices are based on Venezuela and Brazil
- the ROW (Rest of the world) prices are an average of EUR, EET, FSU and AFR

2.3.2 Bilateral trade flows

EPPA incorporates bilateral trade data from the GTAP5 dataset (in $10 billion). Disaggregating this data is quite challenging, as very little information for all countries' bilateral trade flows is available. We use the physical bilateral trade flow data for OECD regions[15] from the IEA Oil Information database (in million tons), to construct one bilateral trade flow matrix per refined product, such that the total exports or imports of OECD countries (the sum over a line

---

[13] As much as 20% of petroleum coke can be co-fired with coal in a coal power plant, without any major process adaptation.

[14] We use IEA historical price data (Oil Information, 2004) for gasoline and naphtha between years 1980 and 2004 to regress the price of naphtha on the price of gasoline. We find a 0.85 coefficient (R^2 = 0.94, t-stat = 23). Therefore we assume that the price of naphtha is 85% of the gasoline price.

[15] The IEA Oil Information database, 2004, only provides physical bilateral trade flows *from* or *to* OECD countries.

or a column of the bilateral trade matrix) are equal to the total exports/imports data (by country) provided by the IEA Extended Energy Statistics (IEA, 2005a). We then complete this matrix with data for the other regions[16], such that:

- the total exports or imports of a given region still equals the total exports or imports values specified in the IEA Extended Energy Statistics
- the most important aspects of oil products trade are respected, e.g. Russia is a big exporter of most refined products, Asian countries are big importers of diesel and heavy fuel oil, etc.

We then multiply these physical bilateral trade flows with the products' prices and calibrate the data so that the sum of trade between region *r* (destination) and region *r'* (origin) over the different refined products equals the total refined oil bilateral trade flows given by the GTAP5 dataset ($wtflow0_{ROIL,r,r'}$). This provides us with a bilateral trade flow matrix in value terms for every refined product: $Wtarg_p$. Then, we also multiply the physical imports and exports data from section 2.2.4. by the products' prices, and calibrate the data to the GTAP5 total imports and total exports value flows (respectively $xm0_{r,ROIL}$ and $es0_{r,ROIL}$), so that we obtain imports and exports vectors for every refined product: $Xtarg_f$ and $Etarg_p$. $Wtarg_p$, $Xtarg_p$, and $Etarg_p$ finally serve as targets for a minimization program that solves the following system:

$$Min_{wtflow0_{f,r,r'}} \sum_f \left(\sum_{r,r'} \| wtflow0_{f,r,r'} - Wtarg_{p,r,r'} \| + \sum_r \| xm0_{r,f} - Xtarg_{r,p} \| + \sum_r \| es0_{r,f} - Etarg_{r,p} \| \right)$$

Such that:

$$\begin{aligned}
&\sum_{f} wtflow0_{p,r,r'} = wtflow0_{ROIL,r,r'} \\
&\sum_{r,f} wtflow0_{p,r,r'} = es0_{r',ROIL} \\
&\sum_{r',f} \Phi_{f,r,r'}(wtflow0_{p,r,r'}) = xm0_{r,ROIL} \qquad (1) \\
&\sum_{r} wtflow0_{p,r,r'} = es0_{r',p} \\
&\sum_{r'} \Phi_{f,r,r'}(wtflow0_{p,r,r'}) = xm0_{r,p}
\end{aligned}$$

with:

- $wtflow0_{p,r,r'}$ being the bilateral trade flows of product *p* between region *r'* (origin) and region *r* (destination),
- $wtflow0_{ROIL,r,r'}$ being the bilateral trade flows of the refined oil commodity between region *r'* and region *r*, as given by the GTAP5 dataset,
- $es0_{r',ROIL}$ being total refined oil exports of region *r'*, as given by the GTAP5 dataset,
- $xm0_{r,ROIL}$ being total refined oil imports of region *r*, as given by the GTAP5 dataset,
- $\Phi_{p,r,r'}$ being a function which adds the export taxes, transports costs, and import tariffs to the trade flows of product *p* between region *r* and region *r'*.

[16] Especially non-OECD trade with non-OECD countries.

2.3.3 Supply and demand

Targets and basic conditions for minimization

On the demand side, the value flows are more detailed than the physical flows as they both specify:

- the consumption of domestically produced goods: *xdp0(region r, good g, sector s)* for industrial sectors and *xdc0(region r, good g)* for households,
- the consumption of imported goods: *xmp0(region r, good g, sector s)* for industrial sectors and *xmc0(region r, good g)* for households.

Using our disaggregated supply and demand physical flows along with the prices of refined products, we can determine targets for a minimization program which would solve the system of equations in (2). In order to assign a target for consumption of imported vs. domestically produced refined products, we make the rough assumption the consumption share of a given refined product is the same for both types of consumption, equal to the total share (imported + domestically produced) of that refined product in total consumption of petroleum products. We then minimize the distance between the supply and demand variables and these targets, such that the following conditions are verified:

$$\begin{aligned}
&xp0_{r,p} = \sum_{s} xdp0_{r,s,p} + xdc0_{r,s,p} + es0_{r,p} && \text{(a)} \\
&xm0_{r,p} = \sum_{s} xmp0_{r,s,p} + xmc0_{r,p} && \text{(b)} \\
&xp0_{r,ROIL} = \sum_{p} xp0_{r,p} && \text{(c)} \\
&xdp0_{r,s,ROIL} = \sum_{p} xdp0_{r,s,p} && \text{(d)} \qquad \text{(2)} \\
&xmp0_{r,s,ROIL} = \sum_{p} xmp0_{r,s,p} && \text{(e)} \\
&xdc0_{r,ROIL} = \sum_{p} xdc0_{r,p} && \text{(f)} \\
&xmc0_{r,ROIL} = \sum_{p} xmc0_{r,p} && \text{(g)}
\end{aligned}$$

with:

- p being any of the six categories of refined products,
- $es0_{r,p}$ and $xm0_{r,p}$ being calculated in section 2.3.2.

It can be noted that some of the equations in (2) are collinear:

- if (a), (d), and (f) are verified, (c) is necessarily verified,
- if (b) and (e) are verified, (g) is necessarily verified.

Final demand for refined products

The previous conditions alone do not guarantee that the disaggregated household own-supplied transport refined products consumption will remain consistent with the original EPPA4 data, i.e. the following equation as defined in Paltsev et al. (2005):

$T\_ROIL_r = OS_r \times TOS_r$

Therefore, we add the two equations in (3) to the previous system (2) to make sure this condition is respected:

$$hhost_{r,p} \leq xdc0_{r,p} + xmc0_{r,p} \qquad \text{(h)} \qquad (3)$$

$$\sum_p hhost_{r,p} = \mathrm{OS}_r \times \mathrm{TOS}_r \qquad \text{(i)}$$

with:

- $hhost_{r,p}$ being the household expenditures on refined product p for own-supplied transportation,
- OS_r being the household expenditures on refined products for own-supplied transportation as a share on the total household expenditures on refined products,
- TOS_r being the total household expenditures on refined products.

Solving this system (equations (1) + (h) + (i)) provides us with a balanced, disaggregated dataset for EPPA. Slight corrections on the resulting value flows are sometimes necessary to make value shares more consistent with observed data.

2.4 Taxes, tariffs, transports costs

We assume all taxes and import tariffs are the same for all refined products, equal to the ones used for EPPA4's single refined product ("*ROIL*") commodity. For example, we assume that in Europe, the final fuel tax on gasoline is the same as the tax on diesel oil. Such an assumption is obviously very rough, and further improvements might be needed in order to represent specific national energy policies that might favor some products over others (i.e. reduced taxation of diesel oil in France, Germany). However, these types of improvements would require rebalancing parts of the dataset.

For international trade, we also assume that transport costs of the different refined products are proportional to the value being transported. Therefore, $vtwr_f$, the cost of transporting a value Q_f of product f from region r to region r' is such that:

$$vtwr_{f,r,r'} = \frac{Q_f}{ROIL} \times vtwr_{ROIL,r,r'} \qquad (4)$$

with:

- $vtwr$ being the cost of transport of the single refined oil commodity from region r to region r', as used in EPPA4,
- $\sum_f Q_f = ROIL$ = total value of refined products being transported from region r to region r'.

Once again, this assumption is the simplest way of disaggregrating transport costs data, and a more accurate way of representing product-specific costs would require further modifications in the GTAP dataset.

2.5 Correction of the refining sector's energy inputs

For certain regions, the physical data as given by the GTAP5 dataset underestimates the consumption of electricity or natural gas or the own-consumption of petroleum products by the refining sector. Also, the value flow data in EPPA4 often underestimates the natural gas consumption by the refining sector. For example, according to the data in EPPA4, no natural gas goes to European refineries, when in reality it is widely used as a fuel or as a feedstock for hydrogen production: in 1997, natural gas represents 15% of the total energy consumption by refineries in the Netherlands. This likely reflects the fact that own-consumption of fuel by a company is not recorded as a separate sale and purchase. We are interested in the emissions of CO_2 and other pollutants that stem from combustion of these fuels. Consequently, we change the physical flow data to make it more consistent with the IEA Extended Energy Statistics. The new data is shown in **Table 6**.

The value flow data is more complex to change, as it has to remain balanced with the rest of the economy: therefore, in a few regions, the final data probably still underestimates the refining sector's expenditures on natural gas.

2.6 Carbon emission factors

The Environment Protection Agency's Inventory of US GHG Emissions, 2004, provides the carbon content of different refined products, in teragrams of carbon per quadrillion Btu. We convert this data in 100 million tons per exajoule (EJ), which is the unit used in EPPA, and multiply it the EPA-based oxidization factor of 99%. The resulting emission factors are shown in **Table 7**.

Table 6. Changes in the refining sector's consumption of natural gas and electricity.

	GAS (EJ)		**ELEC** (Tn kWh[17])	
	EPPA4	**EPPA–ROIL**	**EPPA4**	**EPPA–ROIL**
USA	0.01356	0.8	3.27E-05	0.061
CAN	0.014916	0.437	0	0.005
MEX	0.000177	0.523	9.98E-06	0.005
JPN	0	0.183	4.51E-06	0.01
ANZ	0.007158	0.166	0	0.002
EUR	0	0.669	4.45E-05	0.037
EET	0	0.097	5.28E-06	0.028
FSU	0.003146	0.297	2.03E-05	0.107
ASI	0.000822	0.24	3.01E-05	0.005
CHN	0	0.05	2.27E-05	0.07
IND	0.000704	0.112	0	0.011
IDZ	0	0.151	1.37E-06	0.001
AFR	0.000629	0.579	2.24E-06	0.013
MES	0.000303	2.273	0	0.019
LAM	0.001637	0.62	1.35E-05	0.008
ROW	0	0.018	4.25E-06	0.008

[17] Trillion kWh: energy unit used for the electric sector in EPPA.

Table 7. Carbon emission factors (100MtC per EJ).

	EPA Factors	Final Factors
LPG	0.1773	0.1628
Gasoline	0.1991	0.1828
Diesel	0.2018	0.1858
Heavy Fuel Oil	0.2127	0.1958
Petroleum Coke	0.2754	0.2527
Other Petroleum Products		EINT sector: 0.1828 other sectors: 0

Our "Other petroleum products" category in EPPA-ROIL consists mainly of refined products not destined for energy uses which are generally not a source of CO_2. However, naphtha-related products used as petrochemical feedstocks, e.g. for ethylene or propylene production, are partly oxidized, and therefore do emit CO_2. For our model, we roughly assume that all "Other petroleum products" consumed by the Energy-Intensive sector (EINT) are naphtha. As the naphtha carbon content is very close to that of gasoline, the carbon emission factor we use for the "Other petroleum products" used in the Energy-Intensive sector is the same. The carbon emission factor for "Other petroleum products" is zero in other sectors.

With the product-specific emission factors, global carbon emissions from refined products use amount to 2.92 GtC in the 1997 EPPA calibration year, whereas the original emissions from EPPA4's refined oil commodity amount to 2.69 GtC. We recalibrate our emission factors for the disaggregated refined products so that global CO_2 emissions are the same as in EPPA4. **Table 8** compares regional emissions between EPPA4 and the disaggregated model, after this recalibration. Except for Mexico, China, and the Middle East, the variation is very small (5% maximum) and within the range of uncertainty of emissions data. The final carbon emission factors used in our disaggregated EPPA version are shown in Table 8.

Table 8. Total carbon emissions from refined products, by region (100MtC per EJ).

Region	EPPA4	EPPA4 – disaggregated ROIL	Difference (%)
USA	6.757	6.916	2.35
CAN	0.705	0.732	3.83
MEX	0.662	0.735	11.03
JPN	2.010	1.905	–5.22
ANZ	0.342	0.351	2.63
EUR	5.218	5.052	–3.18
EET	0.454	0.429	–5.51
FSU	1.409	1.404	–0.35
ASI	2.056	1.953	–5.01
CHN	1.523	1.360	–10.70
IND	0.684	0.656	–4.09
IDZ	0.405	0.424	4.69
AFR	0.936	0.969	3.53
MES	1.500	1.810	20.67
LAM	1.581	1.568	–0.82
ROW	0.631	0.605	–4.12
Total	***26.873***	***26.869***	***+0.01***

3. IMPROVING EPPA'S REPRESENTATION OF PETROLEUM PRODUCTION

3.1 Oil products trade

Naphtha, gasoline, diesel, and, to a lesser extent, LPG, are globally traded commodities on international markets such as the New York Mercantile Exchange (NYMEX). Therefore, we assume that the corresponding categories (RGAS, GSLN, DISL, OTHP) of refined products are homogeneous for trade. Petroleum coke (COKE) is not a globally traded commodity, and more difficult to transport, so we assume its trade specification is Armington (Armington, 1969), i.e. products from different regions are not perfect substitutes for one another. Finally, even though heavy fuel oil is traded on global markets, we use an Armington trade specification to constrain its flows in the model: with a homogeneous specification, regions where upgraders are less costly to implement (mark-up factors in section 3.5.3) will unrealistically convert all their domestic heavy fuel oil production into transportation fuels, and massively import the product from other countries to meet industrial demand.

3.2 The refining industry's production function

3.2.1 The CET function for outputs

Previously, all the sectors in EPPA were single-output sectors. The disaggregation of the refined oil commodity into six different categories of refined products leads us to introduce a new, multi-output, production function. To be compatible with the MPSGE language used for EPPA, the production function is designed as a constant elasticity of transformation (CET) function on the output side, and as a constant elasticity of substitution (CES) function on the input side. In a computable general equilibrium model like EPPA, the production function is separable between inputs and outputs, i.e. there is no direct linkage between individual production factors and products:

CET(product 1, product 2, …) = CES(factor 1, factor 2, …)

We choose to represent the CET function as a single-nest, with a low elasticity of transformation at 0.3, to reflect the rigidity of refinery processes. Indeed, in the past twenty years, the increasingly stringent fuel specifications (sulfur content, quality, volatility, etc.) have considerably reduced the already limited flexibility of refinery processes. An existing refinery generally has to invest heavily in a new unit, such as a conversion unit to further process residual fuel oil, in order to meet a change in the demand mix of products[18].

The limitation with the CES-CET specification is that the function is necessarily continuous and does not grasp situations such as investments in upgrading: if all prices other than *product 1*

---

[18] A good example of this situation is France, where most refineries were built to meet a soaring gasoline demand, long before the French government proposed tax incentives on diesel oil and diesel vehicles. Such incentives have led to the current diesel-dominated French automobile market (70% of new vehicle sales in France), reducing the demand for gasoline. Today, French refineries produce more gasoline and less diesel than consumed domestically, and small-scale process adjustments are not sufficient to adapt production to the recent shift in demand. The construction of the new, costly units destined to narrow the gap between supply and demand for gasoline, diesel, and heavy fuel oil is presently underway, an example being the 500M€ hydrocracker in TOTAL's Gonfreville refinery, in Normandy, France.

remain constant, the function cannot represent the fact that an increase in supply of *product 1* (e.g. after a price increase due to high demand) might require an increase of the input quantity of *factor 1* only. In reality, if crude oil prices are high, and the demand—and price—for light fuels increases, refiners will have an incentive to produce more of the latter, not by increasing their activity (i.e. processing more crude oil and therefore mobilizing a larger amount of all inputs) but by investing in upgrading units to further process heavy fuel oil into lighter fuels (i.e. increasing capital input, but not necessarily crude input, labor, etc., to the same extent). Representing such discontinuities is made possible by the modeling of another production function, representing these upgrading add-ons for refineries (section 3.5.3).

3.2.2 The CES function and refineries' energy efficiency

We keep the same structure for the CES function as that in EPPA4. The only change that we introduce is a lower elasticity of substitution between Energy and Value-Added (the capital and labor bundle), at 0.2 compared to the EPPA4 value of 0.5. Our intent is to limit the possibility of price-driven energy efficiency improvements, as the refining industry's energy efficiency improvements of the past twenty years have been widely offset by the additional energy requirements for further processing the refined products, in order to meet demand and fuel specifications. Also, expected specifications for the upcoming decade in developing countries, especially regarding sulfur, benzene or aromatics in transportation fuels, are very likely to cancel any short-term energy efficiency improvements, if not reduce the global energy efficiency of refineries and increase the CO_2 emissions intensity of refineries:

- CONCAWE[19] (CONCAWE, 2005a) estimates that 10ppm sulfur specifications (which will be mandatory in 2009 with the EU Directive 98/70/EC[20]) could increase refining CO_2 emissions by 5%.
- in another study (CONCAWE, 2005b), CONCAWE estimates that strict poly-aromatics specifications could increase European CO_2 emissions by an additional 10%.

The CES and CET nesting structure of the refining sector's production function is represented in **Figure 2**.

3.2.3 Capital vintaging

In EPPA4, a 30% share of the new capital investment in sectors such as Electricity or Agriculture is vintaged every year, and cannot be reallocated to other sectors in the next period: investments are made more rigid. Vintaged capital depreciates for twenty-five years (five periods of the EPPA model) maximum after which its value is zero. The remaining 70% of capital investment in period *T* is malleable in period *T*+1, and indistinguishable from new investments (Paltsev et al., 2005).

[19] CONCAWE, Conservation of Clean Air and Water in Europe, is the oil companies' European association for environment, health, and safety in refining and distribution.

[20] Sulfur specifications have already decreased from 150ppm for gasoline and 350ppm for diesel in 2000 to 50ppm for both fuels since 2005.

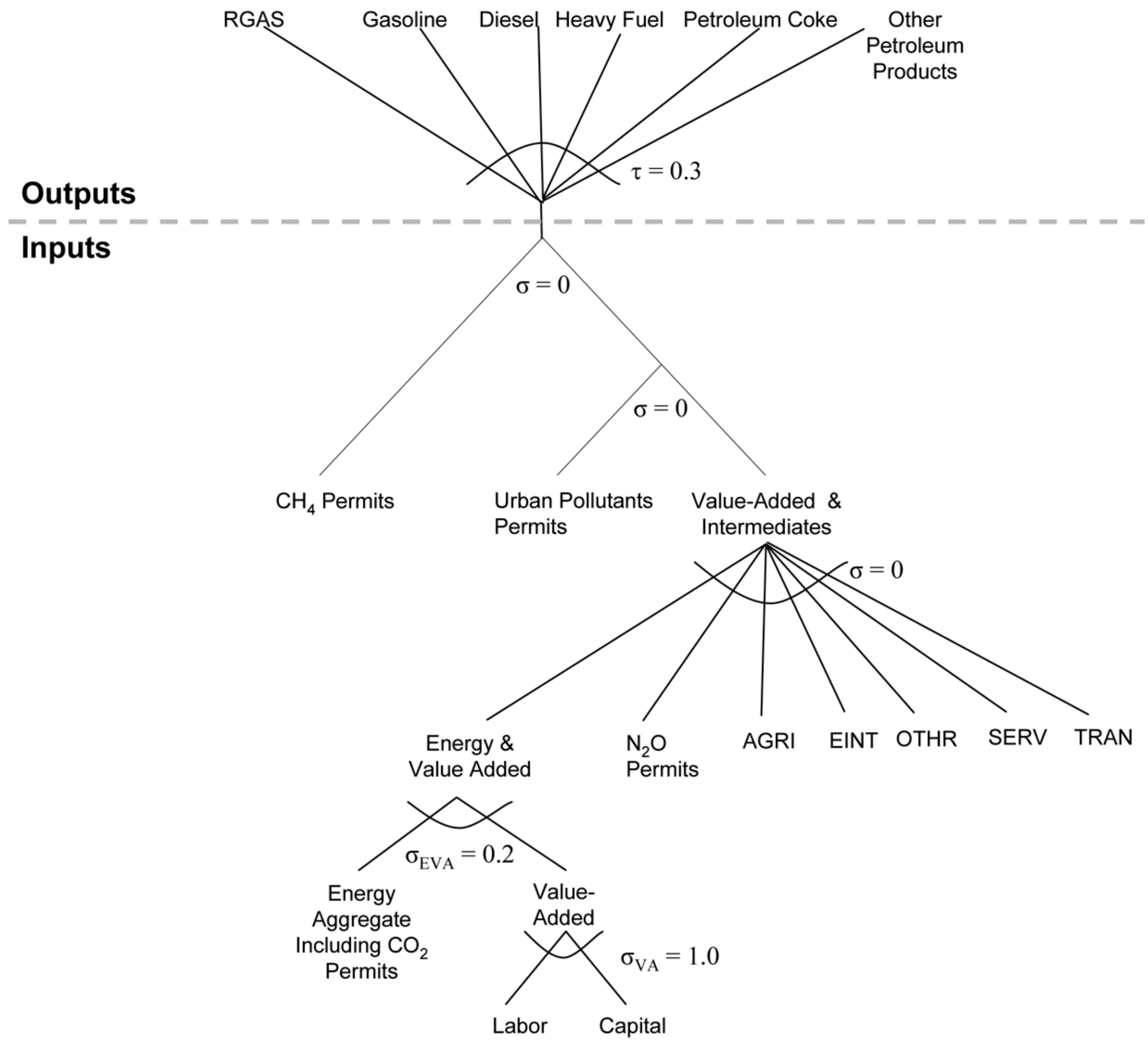

Figure 2. The refining sector's production function.

The same vintaging structure is extended to the refinery sector and the upgrading backstop technology. To better represent the rigidity of investments in the downstream oil industry, we set the clay share at 50%. In period $T+1$, production that uses a vintage of non-malleable capital is such that the input and output coefficients are constrained to be identical to those in period T. The same clay share is applied to the residue upgrading technology which we describe in 3.5.3.

3.3 Energy demand

The EPPA structure is separated into industrial production sectors and a household sector. The demand for fuels is represented by the CES nest. Section 3.3.1 describes those nests applicable to the production sectors, and section 3.3.2 those nests applicable to the household sector.

3.3.1 Industrial energy demand: the "energy bundle"

EPPA4 has two different structures for the "energy aggregate" (also referred to as "energy bundle"): one specific to the electric sector, and one that fits all the other sectors. These nesting structures must be adapted to the increased number of energy commodities with the introduction of six different categories of refined products instead of the single refined oil commodity.

The electric sector

In EPPA4's electric sector, the refined oil commodity is an imperfect substitute for coal, with an elasticity of substitution of 0.3. In our model's energy aggregate, heavy fuel oil and coke are in the same nest with a high elasticity of substitution (equal to 3.0), as both products can be used as fuel for electric power plants (**Figure 3**). The elasticity of substitution between coal and these products remains the same as that of EPPA4 with the refined oil commodity: coke or heavy fuel oil may eventually be co-fired with coal in some regions, but the input shares are unlikely to vary significantly, and increasing that elasticity of substitution has the undesirable effect of strongly reducing consumption of refined products in favor of coal in the electric sector. Light refinery fuels (LPG, gasoline, and diesel) are in another nest, with an elasticity of substitution of 1.0. Their consumption in the electric sector is mostly for utilities' fleet of vehicles (e.g. maintenance vehicles), so the elasticity represents the utilities' ability to substitute from one type of vehicle fuel to another. Diesel is also used as fuel for small-scale diesel electricity generators, but does not substitute well with coal for the base load, hence the low elasticity of substitution at 0.3. Figure 3 represents the nesting structure of electric sector's energy bundle.

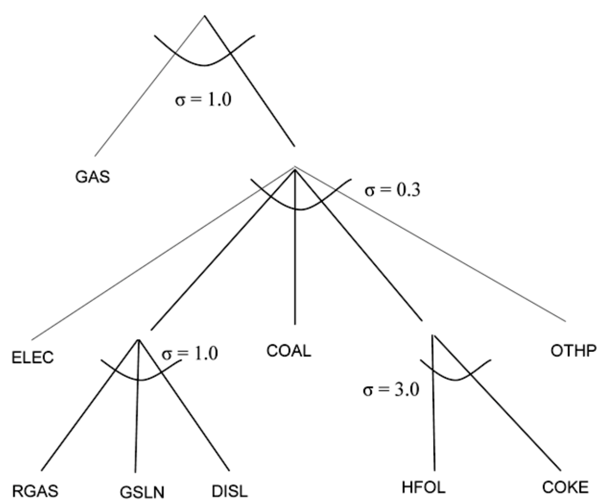

Figure 3. The electric sector's energy bundle.

Other sectors in EPPA

For all other sectors which use energy (Agriculture, Refining, Energy-intensive industries, Services, Transport, Other industries), the vehicle fuels are also in the same nest, with a high elasticity of substitution, and represent mostly the sectors' transportation activities that are not already accounted for in the TRAN sector. However, LPG and diesel are also used for heating, especially in the services' sector. Heavy fuel oil, petroleum coke, and coal are in the same nest with a high elasticity of substitution, as they are easily substitutable as fuels in industrial processes (**Figure 4**). The "Other petroleum products" category includes either lubricants, bitumen (e.g. for road coating within a factory site) used along with transportation activities, either naphtha, and spirits used as feedstocks for the petrochemicals industry, which hardly substitute with other energy inputs.

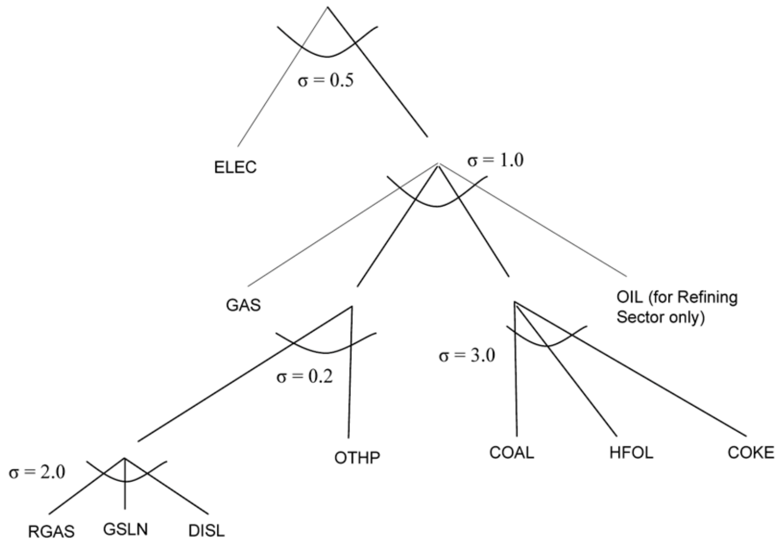

Figure 4. Energy bundle for the other sectors.

3.3.2 Household own-supplied transportation and residential consumption

Household transportation

The vehicle fuels (LPG, gasoline, and diesel) are added through a new nest at the place of the refined oil commodity (**Figure 5**). An elasticity of substitution of 1.0 governs the possibility of switching from one fuel to the other. The CES function being share-preserving, the choice of such a structure enables us to identify the consumption share of every vehicle fuel in a given

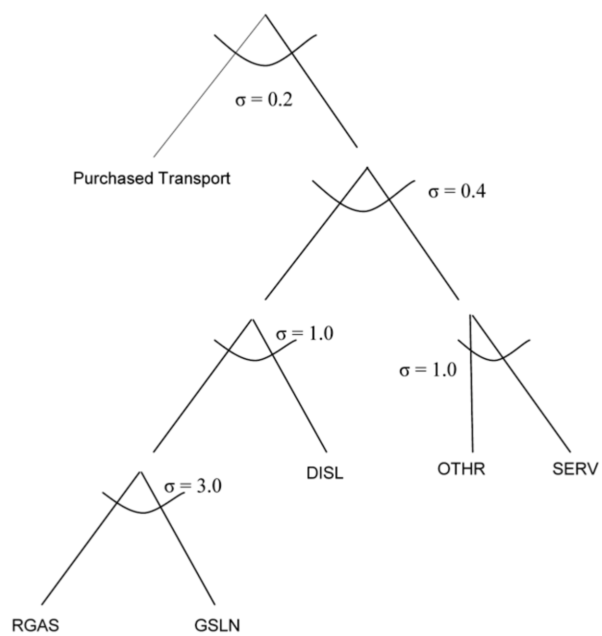

Figure 5. Household transportation structure.

region in the base year. The elasticity of substitution allows gradual shift from one fuel to the other as relative prices change, but tends to preserve the initial shares. This approach is suited for short-term studies with EPPA, as it prevents sudden and unrealistic shifts from one fuel to another that could not be possible given a vehicle fleet. However, in order to study the household consumption of vehicle fuels under climate policies over a longer horizon, it would probably be more accurate to model one production block per fuel type and explicitly vintage the automobile fleet, to capture the dynamics of the vehicle fleet turnover and the possibility of a complete switch from gasoline to diesel or vice-versa.

Residential use

The structure of the consumption production block is unchanged: all refined products used for residential purposes are assumed to be imperfect substitutes for the other energy sources (coal, gas, electricity) with the same elasticity as the one used in EPPA4 (equal to 0.4).

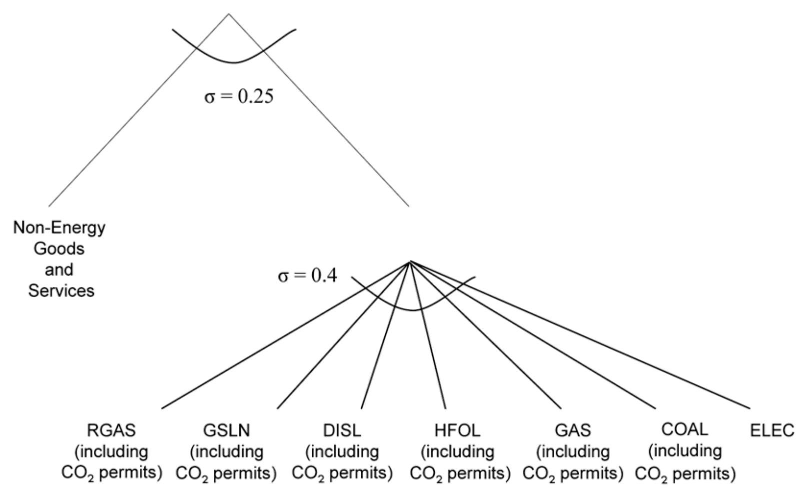

Figure 6. Residential energy consumption, structure of bottom-level nests.

3.4 Biofuels production function

The biofuels backstop technology already modeled in EPPA4 represents a "second generation" biofuels technology, which uses land, capital, and labor to produce a perfect substitute for refined oil. The production function was modeled using data from studies on production of cellulosic ethanol (Paltsev et al., 2005), which many countries consider to have the greatest potential for a technological breakthrough that would provide a carbon-free gasoline. However, there is also a strong potential for advanced biodiesel technologies, such as biomass-to-liquids (BTL), which could compete with cellulosic ethanol as clean energy for transportation. In our model, we assume that the input shares are the same for either advanced biodiesels or cellulosic ethanol, equal to that of the biofuel backstop technology in EPPA4: we represent biofuels production within a single production block with two outputs, carbon-free perfect substitutes for gasoline and diesel. The initial output shares for every region are roughly assumed to follow the consumption shares of gasoline and diesel for private transport, i.e. 99% gasoline-type biofuel and 1% biodiesel in the US, 50% gasoline-type biofuel and 50% biodiesel in

Europe, as we expect countries to favor the technology which helps them meet domestic demand. Just as for the household own-supplied transportation, such a choice for representing biofuels production prevents any sudden shifts in the production of one type of biofuel to the other. For a specific study of vehicle fuel consumption under climate policy over a longer horizon, a more accurate way to represent biofuels production would probably be to use a model with one production block per type of biofuel. Such an approach would also enable to distinguish the cost structure of the two kinds of biofuels, by introducing different input shares or markups for the two technologies.

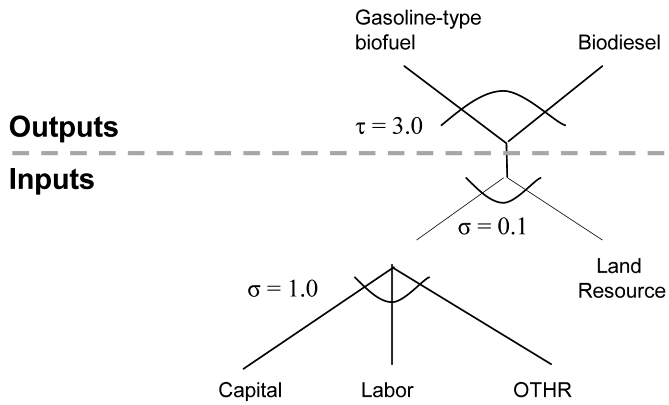

Figure 7. Biofuels production function.

3.5 Residue upgrading technologies

After the 1970s oil shocks, and more recently because of environmental regulations which favor light fuels, heavy fuel oil demand has not been increasing as rapidly as the demand for lighter products such as gasoline or diesel. Consequently, refineries have had to adapt to these changes by further processing residues into higher value products: lighter grades of petroleum products, or even hydrogen. In order to represent refined products' supply as accurately as possible, it is then necessary to add several technological options for residue upgrading. We expand the work done with the EPPA model by McFarland et al (2004) to allow heavy fuel oil or coke as inputs for gasification technologies without (section 3.5.1) or with (section 3.5.2) carbon capture and sequestration. We also model a new upgrading technology (section 3.5.3) to represent the possibility of transforming heavy refinery residues into transportation fuels.

3.5.1 Syngas production from refinery residues

Gasification is a technology which enables the transformation of cheap, dirty fuels, such as coal or petroleum coke, into a higher value clean synthetic gas, a mixture of hydrogen and carbon monoxide, which can serve many purposes:

- substitute for natural gas in power generation;
- hydrogen production (after a water gas shift reaction);
- synthetic fuels production (after Fischer-Tropsch process);
- production of various chemicals (methanol, etc.).

The EPPA model already includes a coal gasification technology, which transforms coal into a perfect substitute for the model's natural gas commodity. As refinery residues can also be gasified, we add two new production blocks with the same structure as coal gasification: one production block represents heavy fuel oil gasification and the other represents petroleum coke gasification. Just as for coal gasification, these two blocks produce a perfect substitute for natural gas.

Based on the National Energy Technology Laboratory's gasification database (National Energy Laboratory, 2005), the efficiency of the different gasification processes is the same for coal, coke, or refinery residue feedstocks, at around 75%-80%. Therefore, we use the coal gasification input shares for the two new gasification production blocks, adjusting the fuel input share to take into account difference in petroleum coke or heavy fuel oil price as compared to coal: we assume that the coke and heavy fuel oil price are respectively 60% and 187% of the coal price. We evaluate the cost of the refinery residue gasification technology relative to its coal competitor, and define this ratio as M, a mark-up factor (**Table 9**). We recalibrate the inputs shares so that their sum is equal to one and that the energy efficiency (energy output divided by energy input) is 75%. This leads us to change the EPPA4 input shares for coal, as these were based on an energy efficiency of 50%.

To verify the previous EPPA4 mark-up for coal gasification versus natural gas production, we evaluate the production cost of synthetic gas (Appendix 2, Table A2.A), and compare it to the assumed production cost of natural gas. Our results are consistent with the 3.4 synthetic gas from coal mark-up factor over natural gas previously used in EPPA.

In reality, residue gasification is mostly used along with a gas turbine for power generation, as steam methane reforming remains the most favored process for synthetic gas—and, ultimately, hydrogen—production to meet the refineries' needs. In the EPPA model, gasification for power generation without CO_2 capture and sequestration is represented indirectly, as the gasified fuel can be used as a perfect substitute for gas in the conventional electric sector.

In reality, residue gasification is mostly used along with a gas turbine for power generation, as steam methane reforming remains the most favored process for synthetic gas—and, ultimately, hydrogen—production to meet the refineries' needs. In the EPPA model, gasification for power generation without CO_2 capture and sequestration is represented indirectly, as the gasified fuel can be used as a perfect substitute for gas in the conventional electric sector.

Table 9. Gasification technologies.

Input shares		**Capital**	**Labor**	**Fuel**	**Other**	**M, mark-up over coal gasification**
COAL	**EPPA4 SYNF-GAS shares**	0.300	0.200	0.400	0.100	1.000
	New shares with 75% efficiency	0.385	0.257	0.230	0.128	1.000
HFOL	SYNF-GAS with HFOL price	0.300	0.200	0.747	0.100	1.347
	new shares (after recalibration and adjustment of efficiency)	0.382	0.255	0.236	0.127	
COKE	SYNF-GAS with COKE price	0.300	0.200	0.240	0.100	0.840[21]
	new shares (after recalibration and adjustment of efficiency)	0.472	0.314	0.057	0.157	

[21] The mark-up cost lower than 1 means that gasifying coke is cheaper than gasifying coal.

3.5.2 Power generation with CO_2 capture and sequestration

We also use previous work done in EPPA (McFarland et al., 2004) on advanced electricity technologies to add two production blocks for heavy fuel and coke integrated gasification combined cycle with carbon capture and sequestration (IGCAP). We assume the same efficiency of 36%, and recalculate the input prices and markups as in section 3.5.1 to take into account the differences in fuel prices. **Table 10** provides the input shares for IGCAP, depending on the type of fuel input.

The penetration of these two technologies is limited by the resource endowment of the coal IGCAP technology. Also, we use the same structure for capital vintaging as that of the coal IGCAP's (McFarland et al., 2004). Because of the different fuel prices, the heavy fuel oil IGCAP is approximately 12% more expensive than the coal IGCAP, and the coke IGCAP is approximately 5% less expensive.

EPPA does not include hydrogen production with sequestration, except in the IGCC technology. A possible clean technology option for refineries is to use hydrogen produced with sequestration. Adding such an option could be the fruit of future work. The CES production structure, through substitution elasticities, represents the ability to produce fuels more cleanly.

Table 10. Input shares for integrated gasification combined cycle with CO_2 capture and sequestration, USA.

Type of fuel gasification	Capital	Labor	Fuel Cost	Capital for sequestration	Labor for sequestration	Capital T&D	Labor T&D
COAL	0.37	0.11	0.12	0.07	0.01	0.20	0.12
HFOL	0.32	0.09	0.25	0.06	0.01	0.17	0.10
COKE	0.40	0.12	0.04	0.08	0.01	0.22	0.13

3.5.3 Modeling of a new upgrading technology

Many different refinery configurations exist, from simple topping[22] or hydroskimming[23], to more complex cracking facilities[24] that can convert distillates or residues into lighter fractions by reducing the carbon-to-hydrogen ratio of the feedstock to increase gasoline or diesel production. As discussed previously, the CES-CET approach can capture some aspects of existing refineries' abilities to shift production among products, but is limited in representing the need for upgrading capacity. Specifying a separate upgrading technology allows greater flexibility in representing the high capital cost and production characteristics of such facilities, such as their considerable energy requirements[25]. Such an addition to the model enables us to represent an important feature of refining processes, which is that producing light products such as gasoline requires more processing than producing heavier products, thus using more energy: consequently the

[22] Topping refineries are refineries with distillation towers only.

[23] Hydroskimming refineries are generally topping refineries with additional processing units such as hydrotreating or catalytic reforming.

[24] Cracking refineries have units such as hydrocrackers or fluid catalytic crackers to process middle distillates. The most complex refineries feature residue upgrading units such as hydroconversion or coking to convert heavy refinery residues (vacuum residue).

[25] Complex refineries with upgrading units may consume twice the energy of simple topping or hydroskimming configurations.

implicit energy cost—and CO_2 cost under carbon constraints—of producing lighter fuels is also greater than for heavier products. In this section, we explain in detail how the upgrading technology function is designed in the model.

Efficiency of upgrading processes

It is generally assumed that the total energy efficiency of refineries ranges between approximately 90% and 95%, depending on the plant's complexity, upgrading units being more energy-intensive than distillation processes. Based on several studies, we estimate the efficiency of our generic upgrading technology at 85%.

Mark-up factor

An essential parameter in our modeling of an upgrading technology is the ratio of the cost of the generic upgrading technology to the cost of the conventional refining technology, which we refer to as the mark-up factor. We need to compare two multi-output production functions: one for the refining sector, one for the upgrading technology. Since the mix of outputs differs significantly between the conventional refining sector and the upgrading technology, the mark-up is obtained by comparing the costs of producing one unit of value, as follows:

$$\text{Mark-up} = \frac{\text{\$ spent per \$ produced by the upgrading technology}}{\text{\$ spent per \$ produced by the conventional refining technology}} \qquad \text{(a)}$$

To calculate this mark-up, we use capital expenditures (CAPEX), operating expenditures (OPEX), and energy consumption data to estimate the production costs of different refinery configurations. We consider four different refinery configurations:

- The hydroskimming refinery: with a distillation capacity of 10Mt per year, and treatment units (both catalytic reforming units and gas-oil desulfurization). We will refer to this refinery as "simple" in our calculations.
- The catalytic cracking refinery, same as the hydroskimming, but with a 1.6Mt per year fluid catalytic cracker (FCC).
- The hydrocracking refinery, same as the hydroskimming, but with a 1.3Mt per year hydrocracker[26] (HCU).
- The complex refinery, with FCC and HCU units.

We compare the costs and revenues of these refineries to those of the two following upgrading configurations, as the data is available in Philips and Liu (2002):

- FCC+DCU: Delayed coker (DCU) with fluid catalytic cracker (FCC);
- ARDS+RFCC: Atmospheric residue desulfurization (ARDS) and residue fluid catalytic cracking (RFCC).

The costs and revenues per processed ton are presented in Appendix 2, Tables A2.B to A2.D. For each configuration, the revenue is calculated by using rough assumptions on product yields. Public data for hydroconversion[27] were not fully available, so this technology was not used to

[26] The hydrocracker processes vacuum gasoils, i.e. the lightest fractions in the heavy fuel oil pool.

[27] Hydroconversion is a hydrocracking process specially designed for heavy residues, such as vacuum bottoms.

assess the mark-up factor. To calculate the energy consumption of the two upgrading configurations, we assume efficiencies of 85% for the FCC+DCU configuration and 82% for the ARDS+RFCC configuration[28]. We also assume a fixed energy price, which is the weighted price average of the energy inputs (see Appendix 2).

Limited data on the cost structure of upgrading units are available: we use data from two different sources: private conversations with industry experts (Source 1) and Philips and Liu, 2002 (Source 2) to calculate the production costs of different upgrading configuration. From one source to the other, the capacity of the units varies considerably (**Table 11**). Industry experts use a rule that doubling capacity entails only a $2^{0.65}$ increase in capital. To put the costs on an equal footing we used this $2^{0.65}$ rule to determine the total cost per ton processed of the following upgrading configurations:

- a 4.4Mt FCC with a 2Mt DCU
- a 5.66Mt ARDS with a 4.74Mt FCC

This time, the results are consistent among the two sources, as shown in **Table 12**.

The mark-up factors for the different upgrading options (i.e. adding an ARDS and a RFCC, or a FCC and a DCU) are calculated using formula (a). **Table 13** shows that they vary between 1.00 and 1.37 approximately, depending on the pre-existing complexity of the refinery: investing in an additional upgrading unit will be less profitable in a complex refinery which already features upgraders than in a hydroskimming refinery. The capacity of the units can also change the mark-up, e.g. from 1.02 to 1.40 for an ARDS+RFCC configuration built in an existing cracking refinery.

Table 11. Upgrading units' capacities.

	FCC+DCU Configuration (Mt/yr)		**ARDS+RFCC Configuration** (Mt/yr)	
	FCC	**DCU**	**ARDS**	**RFCC**
Source 1	1.60	1.20	1.20	1.60
Source 2	4.40	2.00	5.66	4.74

Table 12. Own calculation of production costs ($/t processed), after calibration to same capacity.

Configuration	**With data from source 1**	**With data from source 2**
FCC+DCU	161	158
ARDS+RFCC	176	176

Table 13. Mark-up factors.

Mark-up		**Initial configuration**			
		Simple (10Mt)	**+FCC** (1.6Mt)	**+HCU** (1.3Mt)	**+FCC+HCU**
Unit added	**Simple** (10Mt)				
	+FCC (1.6Mt)	0.89		0.99	
	+HCU (1.3Mt)	0.89	1.01		
	+FCC+HCU	0.93			
	+ARDS+RFCC	1.02 - 1.25	1.14 - 1.39	1.15 - 1.40	1.10 - 1.34
	+FCC+DCU	1.10		1.27	

[28] Including hydrogen production, from methane reforming or gasification.

To determine a reasonable mark-up factor in that range for each EPPA region, we consider two criteria:

- the existing complexity of the region's refineries;
- the regional price of heavy fuel oil.

Indeed, the US or Japan already have a significant installed upgrading capacity, so the mark-up in these regions is high. Latin America and Canada have also heavily invested in upgrading in the 1990s, to face the heavying up of their conventional crude production, and to exploit their considerable non-conventional oil resources (Alberta oil sands in Canada, extra-heavy oils in Venezuela's Orinoco belt or in Mexico), so the mark-up is also on the high end of the range of values. Conversely, regions such as Europe, Africa, China or India have little installed upgrading capacity, so the mark-up is on low end. Southeast Asia (ASI region) has little upgrading capacity, but there is a strong industrial demand for heavy fuel oil, so the price is higher than in other regions (hence the exports from Europe or Russia to Asia) which also explains our choice of a higher mark-up for that region.

The second criterion is important, as our mark-up calculation only considers a global heavy fuel oil price, whereas slight geographical price differences do exist. Indeed, the market price is generally lower in Europe (Rotterdam) where large surpluses exist, than in Asia (Singapore) where demand for heavy fuel oil is high, as shown in **Table 14**. Finally, we assume that mark-up costs vary only between 1.00 and 1.25 (instead of 1.00-1.40), to take into account innovation-related cost reductions. **Table 15** displays the final mark-up factors.

Table 14. Heavy fuel oil (US$ per bbl), 1997-2004 average spot price.

Sulfur Content	**NW Europe** (Rotterdam)	United States	Singapore
Low-Sulfur Heavy Fuel Oil	19.81	21.05	21.96
High-Sulfur Heavy Fuel Oil	18.24	18.48	20.34

Source: IEA Product Spot Prices, Oil Information Database (2005).

Table 15. Final mark-up factor for EPPA regions.

USA	CAN	MEX	JPN	ANZ	EUR	EET	FSU
1.25	1.20	1.20	1.20	1.15	1.1	1.1	1.05
ASI	**CHN**	**IND**	**IDZ**	**AFR**	**MES**	**LAM**	**ROW**
1.10	1.00	1.05	1.00	1.00	1.10	1.15	1.05

Structure of the residue upgrading production function

The residue upgrading production function transforms the heavy fuel oil (HFOL) commodity in transportation fuels, along with petroleum coke and other petroleum by-products.

On the output side, the CET function features a single sub-nest bundling the transportation fuels together. Petroleum coke and other petroleum by-products are in the top-nest (**Figure 8**). Depending on the product prices, refiners will want to enhance the production of LPG and gasoline production (e.g. via coking), or distillates oil (e.g. via hydrocracking), so the high elasticity of substitution between transportation fuels is meant to represent the wide array of technological options for residue upgrading, while the by-products, whether heavy-fuel-like or

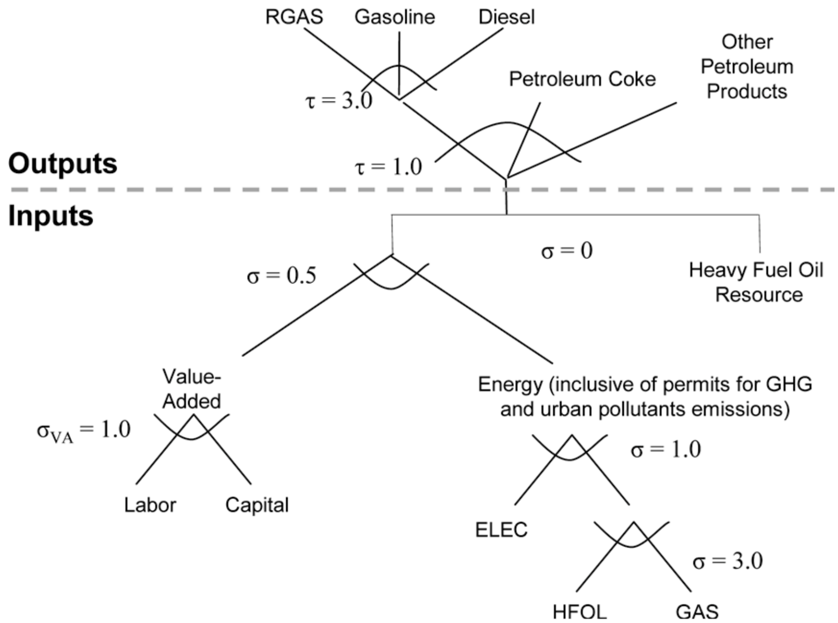

Figure 8. Residue upgrading production function

coke-like, are inevitable. The output value shares are calculated with our regional price estimates (section 2.3.1) and physical shares (**Table 16**) derived from the physical data in Philips and Liu (2002).

On the input side, the CES function's structure is similar to other production functions in EPPA, with a value-added bundle and an energy bundle which are substitutable with an elasticity of 0.5. We distinguish the heavy fuel oil used as an energy source from that which is transformed. The latter is Leontief with other inputs to ensure that the function does not contradict the first principle of thermodynamics (i.e. the conservation of energy: total energy output of the refining sector must be lower than total energy input, including crude oil input). Heavy fuel oil and natural gas serve as fuels for the various upgrading processes or utilities (heaters, boilers, etc.). However, these inputs can also implicitly represent the production of hydrogen, such as that necessary to meet the needs of hydrodesulfurization or hydrocracking processes. The high elasticity of substitution between heavy fuel oil and natural gas illustrates the relative easiness of switching from one fuel to the other, or the ability to produce hydrogen from fuel oil gasification instead of steam methane reforming.

Capital and labor input shares are also derived from CAPEX and OPEX data in Philips and Liu (2002). The physical shares for the energy and resource inputs are obtained by using the mark-up factor, the energy efficiency, and assuming that 60% of upgrading energy use is natural gas, 35% is heavy fuel oil, and 5% is electricity. **Table 17** shows the input shares for the upgrading technology in the USA region (after calibration to 1).

Table 16. Output physical shares for the residue upgrading technology.

RGAS	GSLN	DISL	COKE[29]	OTHP
0.159	0.440	0.284	0.075	0.042

[29] We include residues from upgrading processes (FCC slurry, deasphalter pitch) in the "COKE" category.

Table 17. Input shares for upgrading technology in USA region.

HFOL Resource	HFOL Energy	ELEC	GAS	Capital	Labor
0.419	0.027	0.004	0.046	0.396	0.108

We assume that our upgrading technology can only use domestically produced residues. Such an assumption is reasonable, as due to transport costs, residues are unlikely to be exported over a long distance to be upgraded in another region[30].

4. REPRESENTING CHANGES IN THE CRUDE SLATE

Significant changes in the crude slate are expected with the depletion of conventional oil resources and the increasing importance of non-conventional oils in global production. First, as large, existing reservoirs deplete, production will yield heavier and sourer crudes: such a phenomenon has already been observed in mature oil fields throughout the world. Second, the production share of extra-heavy oils is expected to grow, mostly with the development of oil sands and extra-heavy oil projects in Canada and Venezuela respectively. Finally, production of non-conventional extra-light crudes, such as gas-related liquids[31] (natural gas liquids[32] and condensates[33]), is also expected to grow substantially, especially with LNG projects in Africa or the Middle East.

This section describes how we represent these changes in the crude mix. In the first subsection, we explain the disaggregation of non-conventional extra-heavy oil from conventional oil reserves, using the EPPA4 documentation (Paltsev et al., 2005). In the second subsection, we describe the modeling of two non-conventional oil backstop technologies: a bitumen production function, and a bitumen upgrading function. In the last subsection, we address the issue of modeling the other expected changes in the crude slate: the heavying up of conventional crudes and the growing production of gas-related liquids.

Generally, bitumen is the name given to oil produced from Canadian oil sands, and extra-heavy oil is the name given to Venezuelan non-conventional oil. In the following, we indifferently refer to both as bitumens, natural bitumens, extra-heavy oils, or non-conventional oils. Non-conventional extra-light crudes are simply referred to as extra-light crudes.

4.1 Reserves

The documentation of EPPA4 (Paltsev et al., 2005) provides data which enables us to calculate both conventional and non-conventional oil reserves (oil sands in Canada and extra-heavy oils in Venezuela). These values originally come from the United States Geological Survey, but are modified to take technical progress into account (e.g. techniques that could

---

[30] Heavy fuel produced in French refineries can be transported to another European (Belgian, Dutch or German) refinery, but generally is upgraded within the EUR region: exports of heavy fuel oil are mostly for industrial consumption.

[31] The term “gas-related liquids” generally refers to hydrocarbon by-products of natural gas. Gaseous at the high pressure of natural gas fields, they are liquid at standard temperature and pressure, and are either directly separated by natural gas field processing, or in LNG plants during natural gas purification.

[32] Natural gas liquids are the light hydrocarbon fractions of gas-related liquids, i.e. typically ethane (C2), propane (C3), butane (C4).

[33] Condensates typically include pentanes (C5) and heavier hydrocarbon fractions.

improve the oil recovery factor, such as enhanced oil recovery) via multiplication by a coefficient which varies between 1 and 1.9. For example, it is generally estimated that Canada's ultimate recoverable reserves of oil sands are around 300 billion barrels (about half of which is currently economic), i.e. 1700 EJ. The EPPA4 data is 3230 EJ, calculated as follows:

$$3230 \text{ EJ} = 1.9 \times 1700 \text{ EJ}$$

Table 18 summarizes EPPA4 oil reserves data, except those for shale oil which is already modeled separately. Non-conventional oils in FSU (Russia) are considered to be medium-heavy crudes, so we still include them in EPPA's OIL (conventional oil) commodity.

Table 18. Oil reserves in EPPA (EJ[34]).

Region	Conventional	Oil Sands/Extra-heavy
USA	1,128.5	
CAN	127.3	3,230
MEX	547.4	
JPN	0	
ANZ	92.5	
EUR	773.8	
EET	57.7	
FSU	8,309.0	
ASI	104.0	
CHN	558.0	
IND	144.6	
IDZ	196.5	
AFR	2,100.0	
MES	9,784.6	
LAM	1,897.1	5,600
ROW	5,75.0	

4.2 Extra-heavy oils production functions

Several production techniques exist for the production of extra-heavy oils:

- direct production by conventional processes if the oil is fluid enough;
- thermal production methods, such as Cyclic Steam Stimulation[35] (CSS) or Steam Assisted Gravity Drainage[36] (SAGD);
- mining and extraction for shallow oil sands deposits as in Canada.

Bitumens have a very high viscosity, with a gravity of less than 10 degrees API (**Table 19**), and they do not transport easily. One solution is to dilute it to facilitate transport by pipeline. Partial upgrading bitumen to heavy (10 to 20 degrees API) or medium grade (20 to 25 degrees

[34] Even though oil companies often measure reserves in billion barrels or billion tons of oil equivalent, we display the reserves data in exajoules (EJ), which is the unit used in EPPA.

[35] Also known as "huff and puff", this technology is used for deeper deposits. It requires only one well bore. Steam is injected over several days/weeks to heat the cold bitumen, after which the flow in the well is reversed to produce oil. (definition after Canadian Natural Resources, Limited).

[36] Steam Assisted Gravity Drainage (SAGD) requires two wells: steam is continuously injected in the upper well, mobilizing bitumen above it and causing it to drain in the lower well (Canadian Natural Resources, Limited). This technology is a recent advancement and is not very widespread.

API) is sometimes performed before dilution. In Canada, bitumen can be diluted with synthetic crude (e.g. SynBit), or gas-related liquids (e.g. DilBit[37], **Table 20**). In Venezuela, a successful dilution process consists of emulsifying bitumen with water (Orimulsion).

Another solution is to fully upgrade bitumen into premium synthetic crude, whose quality is comparable to light, sweet crude (**Table 21**). Examples are the Canadian Syncrude project and the Venezuelan Sincor project. In order to process extra-heavy oils into lighter grades, e.g. transportation fuels, upgrading is required, either at the production site or at the refinery. Indeed, when bitumen is diluted and transported as a heavy or medium grade of crude, the client refinery must be capable of processing heavy, sour feeds: as shown in Table 19 and Table 20, the light fraction content of bitumen is much lower than that of conventional crudes.

Table 19. Crude quality, conventional versus non-conventional (at wellhead).

Crude type		Orinoco Cerro Negro*	Athabasca Bitumen**	WTI*** (reference)
API Gravity		8	8	40
% Sulfur		3.8	4.5	0.3
Yields (% wt)	LPG, Naphtha	2	0	38
	Distillate	17	14	31
	Vacuum Gas Oil	26	34	21
	Vacuum Bottoms	55	52	10

Source: Crandall (2002).

* Cerro Negro is a Venezuelan extra-heavy crude (non-conventional).

** Athabasca bitumen comes from Canadian oil sands in the Alberta region (non-conventional).

*** West Texas Intermediate: the reference for crude oil.

Table 20. Crude quality, conventional versus commercial non-conventional.

Crude type		Athabasca DilBit*	Athabasca SynBit**	WTI (reference)
API Gravity		21	20	40
% Sulfur		3.7	2.8	0.3
Yields (% wt)	LPG, Naphtha	25	10	38
	Distillate	15	26	31
	Vacuum Gas Oil	24	37	21
	Vacuum Bottoms	36	27	10

Source: Crandall (2002).

* Blend of 68% Athabasca bitumen and 32% condensate.

** Blend of 52% Athabasca bitumen and 48% synthetic crude.

Table 21. Crude quality, conventional vs. premium synthetic.

Crude type		Canadian Synthetic	Venezuelan Synthetic	WTI (reference)
API Gravity		35	32	40
% Sulfur		0.09	0.07	0.3
Yields (% wt)	LPG, Naphtha	21	18	38
	Distillate	40	40	31
	Vacuum Gas Oil	39	42	21
	Vacuum Bottoms	0	0	10

Source: Crandall (2002).

[37] DilBit generally includes bitumen which is already upgraded to heavy or medium grades.

In this section, we detail the two production functions which represent the non-conventional oil industry in EPPA: a first backstop technology models the production of crude bitumen in Canada and Latin America, and a second represents upgrading bitumen into premium synthetic crude. Even though non-conventional oils were already being produced in 1997 in test fields (mostly in Canada), our model represents non-conventional oil production as a backstop technology: it can only emerge after 1997, the EPPA model's base year. This assumption is justified however, as 1997 oil sands production levels were negligible compared to conventional crude production in the same region.

4.2.1 Structure of functions

On the input side, the nesting structure of the two functions is very close to that of the residue upgrading technology, with the same elasticities of substitution. However, the residue upgrading technology's production function is an add-on to the refining sector in EPPA: it is designed such that it cannot emerge independently from refining activity. For this reason, the residue upgrading production function does not use inputs such as Commercial Transport (TRAN) or Services (SERV), as these are already provided by the refining sector. Bitumen production and bitumen upgrading represent an entire production sector—not just a technological add-on to an existing plant, which is why, in addition to the residue upgrading technology inputs, they use inputs from the following sectors:

- TRAN (Transport sector): inbound and outbound logistics
- EINT (Energy-Intensive sector): steel, petrochemicals for rig or plant construction
- SERV (Insurance or banks)

We add RGAS (refinery gases) as an input to represent the small portion of gas-related liquids used for dilution that cannot be recycled. Because RGAS is not combusted in the production process, RGAS consumption is not a source of CO_2 emissions.

Given the considerable amounts of CO_2 emitted by non-conventional oils production and upgrading, It is likely that oil companies will want to mitigate emissions under stringent carbon policies. Thus, we introduce some flexibility in our production functions: CO_2 capture and sequestration increases energy consumption, so we model energy as a substitute for CO_2 emissions. The structure of the bitman production function is shown in **Figure 9**, and the bitumen upgrading function is shown in **Figure 10**.

Bitumen production function

The bitumen production function produces an intermediate good which is:

- upgraded in the producing region;
- used as a substitute for heavy fuel oil in bitumen producing countries (e.g. Orimulsion in Venezuela);
- exported to another region where it will be upgraded.

The function consumes non-conventional oil reserves, which are depleted in a simple depletion module similar to the one used in EPPA4 for shale oil (Paltsev et al., 2005).

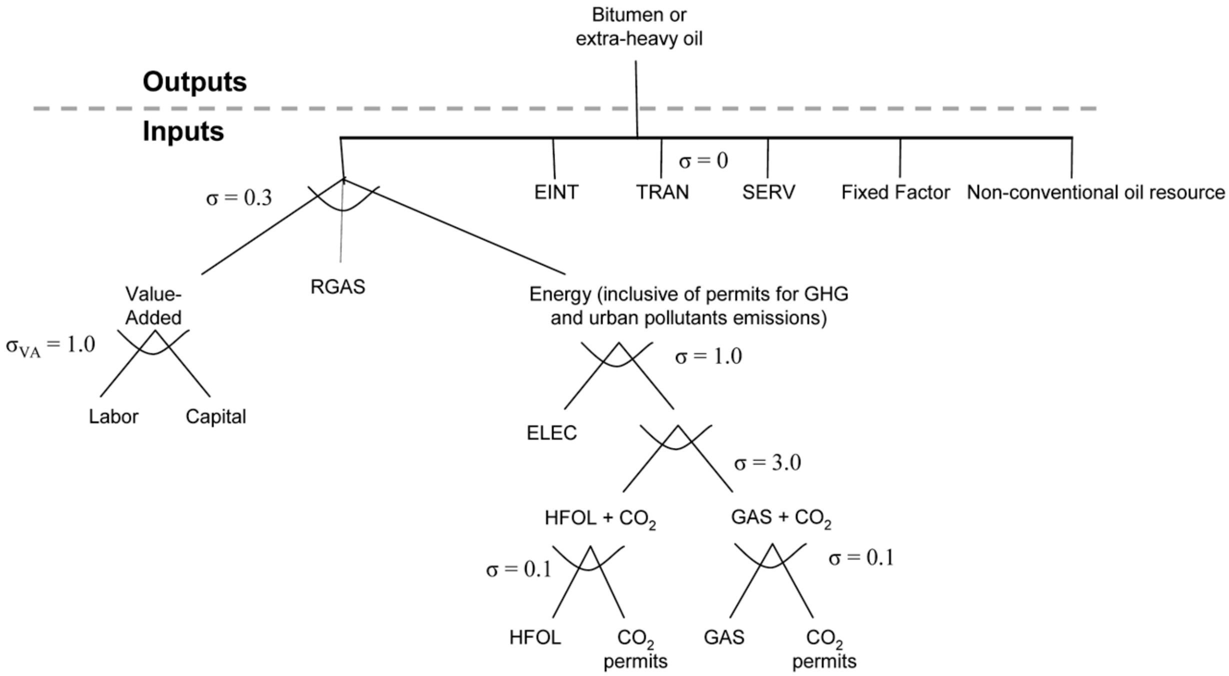

Figure 9. Bitumen production function.

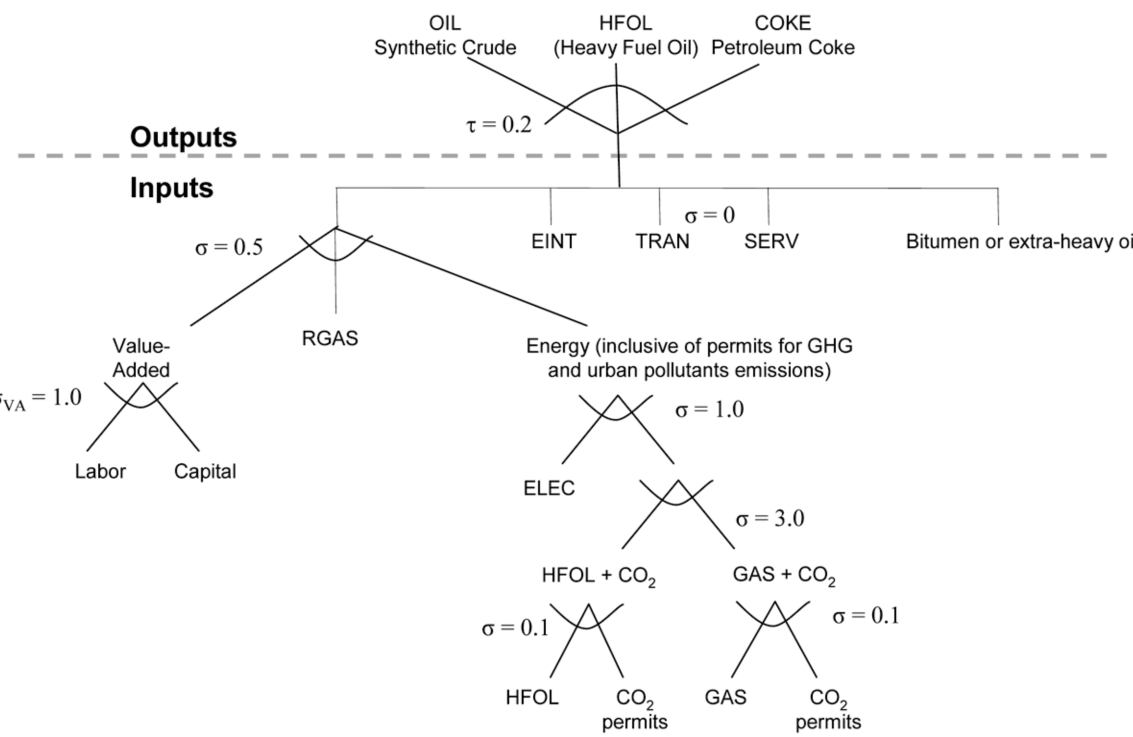

Figure 10. Bitumen upgrading function.

We also introduce a S-shaped fixed factor constraint (Appendix 3, Figure A3.1) to limit their development to the currently forecasted levels (Appendix 3, Table A3.A). Without such a constraint, huge quantities of bitumen are produced almost as soon as the backstop production function is activated in the model (from 2000 on), because considerable non-conventional oil reserves are already theoretically economic in Canada and Venezuela, hence the rather low mark-up factors for the production technology (section 4.2.2). In reality, the time needed to bring projects into production (around six years for mining projects), the high investments costs, and possible technical constraints (e.g. access to water for steam production in Canada) limit the immediate availability of these resources. Also, technologies such as gasification SAGD (for steam production) are only at the beginning of the learning curve. Cost reductions associated with larger scale development of the technologies could allow expand production to the deeper deposits. The downside of using such a fixed factor constraint is that the fixed factor price has to soar quickly to limit the production of the otherwise cheap bitumen. Therefore, the fixed factor cost ultimately outweighs the carbon costs in a climate policy scenario and the same levels of bitumen production are observed in the reference (no policy) and policy scenarios, a result somehow inconsistent with what one could expect. Indeed, even though most of the non-conventional oil supply chain CO_2 emissions come from bitumen upgrading, and climate policy does have a significant impact on that activity in our model, bitumen production can still represent a non-negligible amount of CO_2 emissions, especially in Canada where steam-intensive processes are a common requirement, and should be affected by carbon constraints. Our results are equivalent to assuming that bitumen are so inexpensive relative to crude oil that production will be economic, whether or not project developers have to pay for the associated carbon emissions, or for substitution towards carbon-free energy sources.

Bitumen upgrading function

The bitumen upgrading function produces a perfect substitute for conventional oil (OIL commodity), along with the two heavy petroleum by-products: HFOL (heavy fuel oil from hydrocracking upgraders) and COKE (petroleum coke from coking processes). We assume that the elasticity of transformation which governs the change in output shares is set at the low level of 0.3, as upgrading processes inevitably yield heavy residues. We also assume that only “neighboring” regions of Canada and Venezuela (USA, Japan, Russia, Southeast Asia, China, India) are potential importers of bitumen. Indeed, transport of bitumen over a long distance is expensive, and might affect bitumen upgrading economics for regions which have easier access to other types of crude oil. The bitumen upgrading backstop can then only emerge in these neighboring regions or in the CAN and LAM regions where bitumen is originally produced.

Even though bitumen upgrading and residue upgrading processes are very similar and transform relatively similar products (natural bitumen vs. heavy fuel oil), we cannot simplify our model by using the residue upgrading function—instead of introducing a new bitumen upgrading function—as a sink for non-conventional oil. Indeed, bitumen upgrading only yields superficially finished petroleum products which are then blended to produce synthetic crude oil, whereas residue upgrading must be integrated with a refinery, and the capacity of certain refinery units must be expanded, in order to process heavy fuel oil into market-ready petroleum products (e.g. that meet fuel specifications).

4.2.2 Mark-up factors

There are various estimates of the cost of producing bitumen depending on the quality of resources and how it is recovered: the cost of producing one barrel of bitumen is within a $4-16 range. In Canada, bitumen production by mining and extraction costs $8-12 per barrel (Cupcic, 2003). Estimates for the costs at the Sincor project (Venezuela) are around $4-6 per barrel (Cupcic, 2003). According to our estimates using data from the Canada Natural Energy Board (2004), production costs with SAGD in Canada are higher at around $16 per barrel (Table 24). We assume that bitumen is a perfect substitute for heavy fuel oil within the country in which it is produced. We assume bitumen production costs in Canada and Venezuela to be $10 and $8 per barrel, with a mark-up factor of 0.9 and 0.7 respectively.

Estimates of the costs of synthetic crude produced from bitumen vary significantly among the different available sources. Using data from the Canada Natural Energy Board (2004), we estimate that upgrading one barrel of bitumen into light synthetic crude costs another $15 per barrel (see Table 24). Canada's Syncrude declares bitumen production and upgrading costs under $20 per barrel in 2000 (before the recent increase in natural gas prices), while the Sincor project's upgrading costs are around $6 per barrel. We assume that synthetic crude is a perfect substitute for crude oil: mark-up factors of 1.08 and 1.05 for Canada leads to production costs of respectively $19 and $15.40 per barrel of oil equivalent (boe) produced, including coke and heavy fuel by-products, i.e. respectively $21.80 and $17.70 per barrel of synthetic crude.

We assign higher mark-up factors for upgrading bitumen in other regions to represent the additional costs[38] of transporting bitumen from oil fields to refineries. For example, in the US, a mark-up factor of 1.25 translates into a production cost of $24.10 per barrel of synthetic crude, i.e. $2.30 per barrel more than the actual cost of bitumen in Canada, thus taking into account the transportation costs from Canadian oil sands fields to US refineries.

Table 22. Mark-up factors for bitumen upgrading.

USA	CAN	JPN	FSU	ASI	CHN	IND	LAM
1.25	1.08	1.30	1.30	1.30	1.30	1.35	1.05

4.2.3 Output and input shares

Output shares for the bitumen upgrading function

We use the TOTAL Sincor project in Venezuela as our basis to determine outputs shares for the bitumen upgrading function. The Sincor upgrader consists of a coker which processes 200 thousand barrels per day (kbd) extra-heavy oil (blended with 70 kbd of recyclable dilutent), and the yield is 180 kbd synthetic crude, along with 5800-6000 t/d of petroleum coke (Cupcic, 2003).

200kbd extra-heavy oil = 30,500 toe / day
5,800-6,000 t/d petroleum coke = 4,300-4,400 toe / day

[38] In a general equilibrium model like EPPA, the price equals the marginal cost as all production sectors make zero economic profit. Thus, in equilibrium, a difference in prices can be directly interpreted as a difference in costs.

Hence, output is 12.5% coke, 87.5% synthetic crude. Coking processes are by far the lowest capital investments for upgrading extra-heavy oils, and represent the majority of existing or planned upgraders. However, coking is not the only option for upgrading, and hydrocracking processes must also be considered. Such processes do not yield coke by-products, but slurries and residues which we include in our HFOL category. Therefore, in our model, we consider the output physical shares for bitumen upgrading are 87% synthetic crude, 10% petroleum coke, and 3% heavy fuel oil. We then use the refined product prices (section 2.3.1) to determine the output value shares of the bitumen upgrading production function in every region.

Input shares

We use assumptions from the Canada National Energy Board (2004) to determine the cost structure of bitumen production and upgrading (**Tables 23** and **24**). According to the Canada National Energy Board report, non-gas OPEX "include purchased power, administration, environmental and other direct costs associated with the operation". No further disaggregation of energy, labor, and overhead costs is provided, nor are data available on non-natural gas fossil energy consumption (e.g. fuel gas, fuel oil own-consumption). In order to obtain labor costs,

Table 23. Cost structure of bitumen production in Canada (USD/bbl).

Cost per barrel of bitumen produced	Mining/Extraction	SAGD
Natural gas (mcf/bbl)	0.27	1.26
Natural gas ($/bbl)*	1.11	5.16
Non-gas OPEX ($/bbl)	4.5	3.75
Capital maintenance ($/bbl)	0.375	0.49
Total CAPEX excluding maintenance ($Bn)	1.35	1.75
Lifetime (years)	42	37
Capacity (bbd)	100,000	100,000
CAPEX ($/bbl)**	3.89	5.20
Transportation ($/bbl)	1.15	1.75
Total cost ($/bbl)	**11.02**	**16.35**

* With natural gas at $4/MMBtu.
** With a 10% capital charge rate.

Table 24. Cost structure of bitumen production and upgrading in Canada (USD/bbl).

Costs per barrel produced	M/E + Upgrading	SAGD + Upgrading[39]
Natural gas (mcf/bbl)	0.75	1.74
Natural gas ($/bbl)*	3.07	7.12
Non-gas OPEX ($/bbl)	7.5	6.75
Capital maintenance ($/bbl)	0.75	0.86
Total CAPEX excluding maintenance ($Bn)	5.48	5.88
Lifetime (years)	44	37
Capacity (bbd)	100,000	100,000
CAPEX ($/bbl)**	16.03	17.46
Transportation ($/bbl)	0.70	0.70
Total cost ($/bbl)	**28.05**	**32.89**

* With natural gas at $4/MMBtu.
** With a 10% capital charge rate.

[39] The cost of production by SAGD and upgrading is not provided by the data source. We roughly assume its cost structure is: SAGD costs + Mining/Extraction and Upgrading costs – Mining/Extraction costs.

energy costs, and other costs (services, etc.) from non-gas operating expenditures data, we make a number of assumptions (detailed in Appendix 3) to determine input shares for both bitumen production and upgrading technologies in Canada.

Data in **Table 25** still have to be adjusted for efficiency, CO_2 emissions, and mark-up factors. For example, bitumen production in LAM (Venezuela) requires little energy compared with bitumen production in CAN, as reflected by the much lower CO_2 emissions (section 4.2.4), so input shares for natural gas, gas-related liquids, heavy fuel oil, and electricity must be changed accordingly. This is described in the following section.

Table 25. Intermediate input shares in CAN region.

Backstop	Gas	Gas-related Liquids	Heavy Fuel Oil	Electri-city	Capital	Labor	Energy-Intensive	Services	Transport	Bitumen
Bitumen production	0.224	0.021	0.005	0.015	0.331	0.241	0.04	0.017	0.106	-
Bitumen upgrading	0.115	0.008	0.015	0.007	0.334	0.054	0.038	0.005	0.021	0.403

4.2.4 Calculating input shares by benchmarking CO_2 emissions and energy efficiency

The most important improvement that can be expected from disaggregating non-conventional oil from conventional oil reserves in the EPPA model is the possibility to take into account the considerable amount of CO_2 emitted in producing and upgrading non-conventional oils in Canada and Venezuela. Indeed, crude oil supply might be strongly affected by climate policy, if high CO_2 prices make non-conventional production and/or upgrading uneconomic. If climate policy is not global, significant carbon leakages might occur if upgrading plants can be displaced from non-conventional oil producing regions subject to carbon constraints, to unconstrained regions. Since precise data on the different energy inputs is not fully available and CO_2 emissions are our central focus in introducing this new level of complexity to the model, we determine realistic energy input shares by benchmarking the production function's CO_2 emissions with estimated CO_2 emissions from existing or planned non-conventional oil projects.

Estimated CO_2 emissions from existing or planned projects

Just like residue upgrading, bitumen upgrading is very energy-intensive: significant amounts of energy are needed to increase the relatively poor hydrogen-to-carbon ratio of natural bitumen and remove sulfur or other impurities. Extraction of bitumen from oil sands mining requires a hot water process to separate bitumen from rock. Thermal recovery processes (Cyclic Steam Stimulation, Steam Assisted Gravity Drainage) both require substantial amounts of steam and hot water. Steam and hot water are generated in gas-, coal-, or fuel oil-fired boilers and thus emit a lot of CO_2.

Depending on the production process and the viscosity of the deposit, the CO_2 emissions intensity of bitumen production ranges from 5 to 100 kg of CO_2 per barrel produced:

- in Venezuela, extra-heavy oils are much easier to produce than in Canada, and CO_2 emissions can be as low as 5-10 kg CO_2 per barrel produced;
- In Canada, SAGD production can lead to CO_2 emissions as high as 100 kg per barrel produced (mining and extraction emissions are twice as low).

Upgrading CO_2 emissions are in the range of 100-120 kg per barrel of processed bitumen.

Input shares calculation

We then modify the input shares in the production functions so that CO_2 emissions intensities are consistent with preceding data:

- For the non-conventional oil production function, we calibrate the GAS and HFOL energy inputs such that CO_2 emissions from non-conventional oil production are 60 kg per barrel produced in CAN, and 10 kg per barrel produced in LAM.
- For the bitumen upgrading production function, we calibrate the GAS, RGAS, and HFOL inputs such that:
  - upgrading energy efficiency is 90% in CAN and LAM, and 85% elsewhere (we assume that CAN and LAM regions can better integrate production and upgrading, e.g. for steam generation);
  - CO_2 emissions from upgrading are around 90-100 kg per barrel of oil equivalent produced (105-120 kg per processed barrel of bitumen).

4.3 Other changes in the crude mix

Other changes in the crude mix include the heavying up of conventional crudes along with reserves' depletion, and the production of extra-light crudes or gas-related liquids. Globally, the effect of the first phenomenon is predominant: crude input to refineries is expected to become heavier worldwide, even though strong regional discrepancies exist:

- in the US, the heavying up of the crude slate is evident, with crude input averaging 30.5 degrees API in 2004 versus 33.5 in 1981 (EIA, 2003);
- in regions like Europe, imports of gas-related liquids and extra-light crudes, mostly from North Africa, should compensate in part for the heavying up of crude production in maturing North Sea oil fields.

Table 26. Input shares (final data[40]).

Input	CAN		LAM	
	Bitumen production	**Bitumen upgrading**	**Bitumen production**	**Bitumen upgrading**
GAS	0.216	0.127	0.049	0.140
RGAS	0.018	0.008	0.012	0.015
HFOL	0.005	0.029	0.002	0.028
ELEC	0.014	0.007	0.014	0.013
K	0.286	0.287	0.391	0.193
L	0.209	0.048	0.228	0.032
EINT	0.035	0.033	0.048	0.022
SERV	0.015	0.004	0.020	0.003
TRAN	0.092	0.018	0.125	0.012
Non-conventional Resource	0.100	-	0.100	-
Bitumen	-	0.439	-	0.542
Fixed Factor	0.010	-	0.010	-
Resulting CO_2 emissions[41] (kg/boe produced)	**55**	**85**	**10**	**85**
Production cost ($/boe produced)	**10**	**19**	**8**	**15**

[40] Bitumen upgrading input shares for USA, JPN, FSU, ASI, CHN, IND are not shown here.

[41] CO_2 emissions come from natural gas and heavy fuel oil consumption, the latter including bitumen own-consumption.

In EPPA–ROIL, we must include both heavying up of the crude slate and increasing supply of gas-related liquids and extra-light crudes, as they can have a significant impact on refining activity: the heavier the crude input, the more heavy petroleum products a refinery will yield. Because global demand for such products is decreasing, and, conversely, demand for light products is increasing, such refineries might have to invest significantly in residue upgrading capacity to stay in business.

A simple way of tackling these issues without adding another level of complexity to the model is to represent them from a downstream point of view, i.e. by their regional effects on the mix of "conventional" refining outputs, i.e. the output of the 1997-calibrated refining sector. Indeed, it is reasonable to assume that in a given region *r* expected to import or produce more heavy crudes, the same amount of crude input to "conventional" refineries will yield more heavy products (heavy fuel oil and petroleum coke) over time. We introduce these as an exogenous change in the CET product shares. Thus, for a given quantity of crude and refinery cost, more of the output is weighted towards heavy products. This trend towards heavier products can be overcome through limited substitution in the refinery CET function as governed by the elasticity of transformation or by adding upgrading capacity and further processing heavy fuel oil.

We impose increasing trends for output shares of heavy petroleum products in the different EPPA regions, based on several prospective studies of crude production and input to refineries. We set the heavying up trends to be more substantial in regions with maturing oil fields, or importing heavier conventional crudes (e.g. North America). In regions with significant reserves of light, sweet crude (e.g. Africa), the trend is less significant. Examples of the effect of these trends on the output share of heavy fuel oil are shown in **Table 27**. Our heavy petroleum products trends are based on CONCAWE (CONCAWE, 1999) estimations for Europe (Appendix 3, Table A3.B), and on our own assumptions for other regions, taking into account the provenance of the crude mix processed by every region's refineries, and the expected future quality of that mix.

As gas-related liquids are included in our RGAS category, and the refinery perimeter in the GTAP data covers both the liquefaction and regasification plants (see Appendix 1, Table A1.A), we proceed in the same way for gas-related liquids, using exogenous increasing output shares for gas-related liquids (RGAS category) in LNG-producing regions (mostly Africa and the Middle East) or gas-producing regions (Russia, Europe, etc.), as condensates are produced along with natural gas. Trends for gas-related liquids production are based on NGLs and condensates production capacity forecasts to 2010, which we compare with IEA data on total gas-related liquids and refinery gas production in 1997 (Appendix 3, Tables A3.C and A3.D).

Table 27. Examples of exogenous change in heavy fuel oil output share for "conventional" refining.

Country	Output share 1997	Output share 2050
USA	4%	7%
EUR	14%	22%

Table 28. Examples of exogenous change in refinery gas output share for "conventional" refining.

Country	Output share 1997	Output share 2050
AFR	25%	34%
MES	28%	40%

5. CAVEATS, POSSIBLE IMPROVEMENTS

With 16 regions, 11 production sectors, and several backstop technologies, the EPPA model is a very detailed computable general equilibrium model of the world economy. However, it remains a highly simplified model, and the limitations that initially stem from the quality of the Social Accounting Matrix dataset, from the constant elasticity of substitution structure used in the MPSGE code, and from the basic assumptions behind a general equilibrium could be accentuated in our disaggregated version of EPPA. The data disaggregation and modeling work open up many opportunities for analyses but numerous possibilities for improvements remain.

Improving EPPA's representation of the oil industry allows us to gain a different industry-specific insight on questions traditionally addressed by bottom-up or partial equilibrium models, which are by nature specifically designed to focus on a particular sector. Indeed, our objective was to design a model enabling us to study the impacts of climate policy on oil products supply and demand in the light of a general equilibrium structure, which best represent inter-sectoral and inter-regional interactions. Using a simplified residue upgrading production function, or representing changes in the crude mix from a downstream point of view, are two examples of how we tried to keep the model as simple as possible while representing the impact of important trends in the oil industry. One could still question the relevance of introducing large amounts of bottom-up information in a mostly top-down economic model, and argue that linking a bottom-up model with EPPA would perhaps be more accurate. Also, further disaggregation of GTAP5 or, more generally, of the national income and product and product account data that are its base, requires a number of simplifying assumptions. Uncertainties and inaccuracies are inevitably increased as we dig into more detail. For example, no complete dataset was available to use as a basis for our disaggregating of the GTAP5 bilateral trade flows of refined products. The flows in GTAP5 are already an interpolation of data, so there is a strong possibility that some of our final trade data for different refined products could differ significantly from actual trade flows. Also, our price assumptions for different sectors, products, and regions (Appendix 1, Table A1.D) requested that we extrapolate from relatively limited data. Indeed, data in such a format for a given year and with such a level of detail is almost impossible to obtain.

This work is a first attempt at representing several oil products in EPPA, and opens the door to many new analyses, such as looking at the impacts of climate and environmental policies on the downstream oil industry, the health effects of gasoline versus diesel for transportation, etc. Yet, many improvements can still be added to our work on EPPA's refining sector, as the following non-exhaustive list of examples illustrates:

- **International trade flows of refined products:** as discussed above, the accuracy of refined products trade flows in both physical and value unit would greatly benefit a more complete database, especially for trade between non-OECD countries.
- **International transport costs:** if GTAP data on transport costs is improved, differentiating transports costs between petroleum products, and also possibly between grades of crude oil would be a valuable improvement to the model.

- **Tax rates:** our model very simply assumes the same tax rate for all refined products. A more accurate portrayal of demand would entail differentiating tax rates among refined products.
- **Biofuels:** as discussed in section 3.4, we modeled biofuels in a very simplified way. Cost structure differences between gasoline-type and diesel-type biofuels could be introduced and regional preferences for a certain type of biofuel over another, for certain crops over others could be more thoroughly discussed.
- **Non-conventional oils:** as discussed in section 4.2.1, though it is necessary to limit bitumen production from oil sands or extra-heavy oil projects in Canada and Venezuela to reasonable forecasted levels, the use of the fixed factor constraint eliminates the potential climate policy impacts on the level of output. Perhaps a better representation of the industry would be possible; for example, increasing the mark-up over time could constrain the total output level and still allow carbon costs to have an impact. However, this would mean that bitumen would become more expensive relatively to crude oil, and the actual values chosen for the mark-ups would need some kind of justification.

REFERENCES

Armington, P.S. (1969). A Theory of Demand for Products Distinguished by Place of Production, IMF Staff Papers 16(1): 170-201

Australian Bureau of Transport and Regional Economics, Department of Transport and Regional Services (2005). “Greenhouse Gas Emissions from Transport - Australian Trends to 2020”, downloaded in June 2006 from: http://www.btre.gov.au/docs/monitoringreports/BTRE_AGO_05.pdf

Bensaid, Bernard (2005). “Road Transport Fuels in Europe: The Explosion of Demand for Diesel Fuel”, Panorama IFP 2005, downloaded in June 2006 from: http://www.ifp.fr/IFP/en/files/cinfo/IFP-Panorama05_10-CarburantsRoutiersVA.pdf

Canada Natural Energy Board (2004). “Canada's Oil Sands: Opportunities and Challenges to 2015”, downloaded in June 2006 from: http://www.neb-one.gc.ca/energy/EnergyReports/EMAOilSandsOpportunitiesChallenges2015_2004/EMAOilSandsOpportunities2015Canada2004_e.pdf

CONCAWE (1999). “EU oil refining industry costs of changing gasoline and diesel fuel characteristics”, Report 99/54, CONCAWE Automotive Emissions Management Group, downloaded in June 2006 from: http://www.concawe.be/1/OJDBGKKDJIBKMGEKOMJCMAAFPDBY9DBYPY9DW3571KM/CEnet/docs/DLS/2002-00222-01-E.pdf

CONCAWE (2005a). “The impact of reducing sulphur to 10ppm max in European automotive fuels”, Report 7/05, CONCAWE Refinery Technology Support Group, downloaded in June 2006 from: http://www.concawe.be/2/OJDBGKKDJIBKMGEKOMJCMAAFVEVD239YBD23BYW3T3BY9LTE4Q/CEnet/docs/DLS/Rpt057-2005-01177-01-E.pdf

CONCAWE (2005b). “Impact of a potential reduction of the poly-aromatics content of diesel fuel on the EU refining industry”, Report 8/05, CONCAWE Refinery Technology Support Group, downloaded in June 2006 from: http://www.concawe.be/3/OJDBGKKDJIBKMGEKOMJCMAAFVEVD2W9YBD23BYW3C3BY9LTE4Q/CEnet/docs/DLS/Rpt058-2005-01178-01-E.pdf

Crandall, Gareth R. (2002). “Non-Conventional Oils Market Outlook”, Purvin & Gertz Inc., International Energy Agency Conference on Non-Conventional Oil: Prospects for Increased Production, November 26, 2002, downloaded in June 2006 from: http://www.iea.org/Textbase/work/2002/calgary/Crandall.pdf

Cupcic, François (2003). “Extra-Heavy Oil and Bitumen, Impact of Technologies on the Recovery Factor, 'The Challenges of Enhanced Recovery'“, TOTAL, ASPO Annual Meeting 2003, downloaded in June 2006 from: http://www.peakoil.net/iwood2003/ppt/CupcicPresentation.pdf

Direction des Affaires Economiques et Internationales/Service Economique et Statistiques – Institut National de la Statistique et des Etudes Economiques (2004). “Les comptes des transports en 2003”, Partie II, downloaded in June 2006 from : http://www.statistiques.equipement.gouv.fr/rubrique.php3?id_rubrique=239

Demailly, Damien (2005). “Notes sur l’industrie du raffinage”, Etude EPE – IDDRI

Dimaranan, B. and R. McDougall (2002). Global Trade, Assistance, and Production: The GTAP 5 Data Base. Center for Global Trade Analysis, Purdue University, West Lafayette, Indiana

Energy Information Administration, Department of Energy (2004). "Annual Energy Review, 2003", downloaded in June 2006 from: http://www.eia.doe.gov/emeu/aer/

Energy Information Administration, Department of Energy (1994). "Household Vehicles Energy Consumption Survey", downloaded in June 2006 from: http://ntl.bts.gov/lib/10000/10600/10690/046494.pdf

European Commission, Directorate-General for Energy and Transport (2003). "European Energy and Transport – Trends to 2030"

Hanou, John (2004). "Why Are Utilities Afraid of Petcoke?", Hill & Associates Inc., McCloskey's Petcoke Conference, July 19-20, 2004

International Energy Agency (2005a). "Extended Energy Statistics", 2005

International Energy Agency (2005b). "Oil Information", 2005

McFarland, J, J. Reilly and H.J. Herzog (2004). "Representing energy technologies in top-down economic models using bottom-up information". Energy Economics, 26: 685-707

Natural Resources Canada, Petroleum Resources Branch (2005). Webpage at the address: http://www2.nrcan.gc.ca/es/erb/prb/english

National Energy Technology Laboratory, (2005). Gasification database. Database is available at http://www.netl.doe.gov/technologies/coalpower/gasification/database, last downloaded in June 2006.

Paltsev, S., L. Viguier, J. Reilly, K.H. Tay and M. Babiker (2004). "Disaggregating Household Transport in the MIT-EPPA Model", MIT Joint Program on the Science and Policy of Global Change, Technical Note 5, Cambridge, Massachusetts: http://mit.edu/globalchange/www/MITJPSPGC_TechNote5.pdf

Paltsev, S., J.M. Reilly, H.D. Jacoby, R.S. Eckaus, J. McFarland, M. Sarofim, M. Asadoorian, and M. Babiker (2005). "The MIT Emissions Prediction and Policy Analysis (EPPA) Model: Version 4", MIT Joint Program on the Science and Policy of Global Change, Report 125, Cambridge, Massachusetts: http://mit.edu/globalchange/www/MITJPSPGC_Rpt125.pdf

Philips, Graham and Liu, Fang (2002). "Advances in Residue Upgrading Technologies Offer Refiners Cost-Effective Options for Zero Fuel Oil Production", Foster Wheeler Corporation, 2002 European Refining Technology Conference, Paris, November 2002, downloaded in June 2006 from:

http://www.fwc.com/publications/tech_papers/files/ERTC%202002%20-%20RESIDUE%20UPGRADING%20ARTICLE.pdf

United States Environmental Protection Agency (US EPA, 2002). "Inventory of US Greenhouse Gas Emissions and Sinks: 1990-2000"

World Business Council for Sustainable Development (2005). "Mobility 2030: Meeting the Challenges to Sustainability", Sustainable Mobility Project, downloaded in June 2006 from: http://www.wbcsd.org/plugins/DocSearch/details.asp?type=DocDet&ObjectId=NjA5NA

APPENDIX 1. DATA DISAGGREGATION

Table A1.A. Relationship between EPPA, GTAP5, and IEA sectors.

Description	EPPA	GTAP5	IEA - Code	IEA - Name
Production of primary energy		PROD	INDPROD	Production
			OSOURCEPRI	From Other Sources - primary energy
Energy (oil, gas, coal, elec) imports and exports		IMP EXP	IMPORTS EXPORTS	Imports Exports
Maritime transport (excl. coastal)	TRAN	WTP	BUNKERS	International Marine Bunkers
		PROD, IMP, ELY	STOCKCHA	Stock Changes
PROD + IMP - EXP - BUNKERS ± STOCKS		*subtotal*	TPES	Total Primary Energy Supply
	ROIL	P_C	TRANSFER	Transfers
Unexplained statistical differences		DIFF	STATDIFF	Statistical Differences
		subtotal	TOTTRANF	Total Transformation Sector
Electricity	ELEC	ELY	PUBELEC	Public Electricity Plant
	ELEC	ELY	AUTOELEC	Autoproducer Electricity Plant
	ELEC	ELY	PUBCHP	Public CHP Plant
	ELEC	ELY	AUTOCHP	Autoproducer CHP Plant
	ELEC	ELY	PUBHEAT	Public Heat Plant
	ELEC	ELY	AUTOHEAT	Autoproducer Heat Plant
	ELEC	ELY	THEAT	Heat pumps
	ELEC	ELY	TBOILER	Electric Boilers
			TPATFUEL	Patent Fuel Plants
			TCOKEOVS	Coke Ovens
	ROIL	P_C	TGASWKS	Gas Works
			BLASTFUR	Blast Furnaces
	EINT	CRP	PETCHEM	Petrochemical Industry
			TBKB	BKB Plants
Primary energy use for the manufacture of finished petroleum products, and corresponding output	ROIL	P_C	TREFINER	Petroleum Refineries
	ROIL	P_C	LIQUEFAC	Liquefaction Plants
			TCHARCOAL	Charcoal Production Plants
	ROIL	P_C	TNONSPEC	Non-specified Transformation
		subtotal	TOTENGY	Total Energy Sector
			MINES	Coal Mines
			OILGASEX	Oil and Gas Extraction
			EPATFUEL	Patent Fuel Plants
			ECOKEOVS	Coke Ovens
	ROIL		EGASWKS	Gas Works
			EGAS	Gasification Plants for Biogas

Description	EPPA	GTAP5	IEA - Code	IEA - Name
			EBLASTFU	Blast Furnaces
			EBKB	BKB Plants
	ROIL	P_C	EREFINER	Petroleum Refineries
	ROIL		ELIQUEFAC	Liquefaction Plants
			ELNG	LNG Plants
	ELEC		POWERPLT	Own Use in Electricity, CHP and Heat Plants
			EPUMPST	Pumped Storage (Electricity)
			ENUC	Nuclear Industry
			ECHARCOAL	Charcoal Production Plants
			ENONSPEC	Non-specified Energy Sector
		OWNUSE	DISTLOSS	Distribution Losses
		subtotal	TFC	Total Final Consumption
		subtotal	TOTIND	Total Industry Sector
Consumption in the Industry Sector	EINT	I_S	IRONSTL	Iron and Steel
	EINT	CRP	CHEMICAL	Chemical and Petrochemical
			NECHEM	Memo: Feedstocks Use in Petchem. Industry
	EINT	NFM	NONFERR	Non-Ferrous Metals
	EINT	NMM	NONMET	Non-Metallic Minerals
	OTHR	TRN	TRANSEQ	Transport Equipment
	OTHR	OME	MACHINE	Machinery
	OTHR	MIN	MINING	Mining and Quarrying
	AGRI	FPR	FOODPRO	Food and Tobacco
	EINT	PPP	PAPERPRO	Paper, Pulp and Printing
	OTHR	LUM	WOODPRO	Wood and Wood Products
	OTHR	CNS	CONSTRUC	Construction
	OTHR	TWL	TEXTILES	Textile and Leather
	OTHR	OMF	INONSPEC	Non-specified Industry
		subtotal	TOTTRANS	Total Transport Sector
Transport	TRAN	ATP	INTLCIAV	International Civil Aviation
	TRAN	ATP	DOMESAIR	Domestic Air Transport
	TRAN, HH	OTP	ROAD	Road
	TRAN	OTP	RAIL	Rail
	TRAN	OTP	PIPELINE	Pipeline Transport
	TRAN	WTP	INLWATER	Internal Navigation
	TRAN	OTP	TRNONSPE	Non-specified Transport
		subtotal	TOTOTHER	Total Other Sectors
	AGRI	AGR	AGRICULT	Agriculture
	SERV	SEV	COMMPUB	Commercial and Public Services
	HH	CWE	RESIDENT	Residential

Description	EPPA	GTAP5	IEA - Code	IEA - Name
	OTHR	AGR, SER, DWE	ONONSPEC	Non-specified Other
		subtotal	NONENUSE	Non-Energy Use
Non-Energy	EINT	CRP	NEINTREN	Non-Energy Use Ind/Transf/Energy
		NETRANS	NETRANS	Non-Energy Use in Transport
		AGR	NEOTHER	Non-Energy Use in Other Sectors

Table A1.B. Conversion factors.

Product	Volume equivalent per ton of product (bbl/ton)	Energy content per ton of product (toe[42]/ton)
Crude Oil	7.37	
Natural Gas Liquids	10.30	
Refinery Feedstocks	7.40	
Additives/Blending Components	7.50	
Non-Crude Refinery Inputs	7.40	
Refinery Gas	9.71	1.15
Ethane	16.85	1.13
Liquefied Petroleum Gases	11.60	1.13
Naphtha	8.50	1.075
Aviation Gasoline	8.90	1.07
Gasoline type Jet Fuel	8.25	1.07
Motor Gasoline	8.53	1.07
Kerosene type Jet Fuel	7.93	1.065
Other Kerosene	7.74	1.045
Gas/Diesel Oil	7.46	1.035
Residual Fuel Oil	6.66	0.96
Petroleum Coke	5.50	0.74
Lubricants	7.09	0.96
Bitumen	6.08	0.96
Paraffin Waxes	7.85	0.96
White Spirit	8.46	0.96
Other Petroleum Products	8.00	0.96

Source: IEA (2005a, 2005b).

[42] Ton oil equivalent. 1 toe = 41.868 GJ

Table A1.C. Estimated refined products prices in 1997 ($10 billion per Exajoule).

Region.Fuel	AGRI	ROIL	ELEC	EINT	OTHR	SERV	TRAN	HH-TRAN	HH-RESID
USA.RGAS	0.55	0.55	0.55	0.55	0.55	0.55	0.55	0.55	0.55
USA.GSLN	0.64	0.64	0.64	0.64	0.64	0.64	0.64	0.64	0.64
USA.DISL	0.47	0.45	0.45	0.45	0.46	0.47	0.50	0.47	0.44
USA.HFOL	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.27
USA.COKE	0.07	0.04	0.08	0.10	0.04	0.07	0.07	0.07	0.07
USA.OTHP	0.32	0.32	0.32	0.32	0.32	0.32	0.32	0.32	0.32
CAN.RGAS	0.55	0.55	0.55	0.55	0.55	0.55	0.55	0.55	0.55
CAN.GSLN	0.64	0.64	0.64	0.64	0.64	0.64	0.64	0.64	0.64
CAN.DISL	0.58	0.56	0.56	0.56	0.57	0.58	0.66	0.62	0.46
CAN.HFOL	0.28	0.28	0.28	0.28	0.28	0.28	0.28	0.28	0.28
CAN.COKE	0.12	0.09	0.09	0.12	0.14	0.12	0.12	0.12	0.12
CAN.OTHP	0.38	0.38	0.38	0.38	0.38	0.38	0.38	0.38	0.38
MEX.RGAS	0.77	0.77	0.77	0.77	0.77	0.77	0.77	0.77	0.77
MEX.GSLN	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90
MEX.DISL	0.41	0.45	0.45	0.45	0.43	0.41	0.47	0.44	0.31
MEX.HFOL	0.18	0.18	0.18	0.18	0.18	0.18	0.18	0.18	0.18
MEX.COKE	0.07	0.04	0.08	0.10	0.04	0.07	0.07	0.07	0.07
MEX.OTHP	0.45	0.45	0.45	0.45	0.45	0.45	0.45	0.45	0.45
JPN.RGAS	0.83	0.83	0.83	0.83	0.83	0.83	0.83	0.83	0.83
JPN.GSLN	0.97	0.97	0.97	0.97	0.97	0.97	0.97	0.97	0.97
JPN.DISL	0.80	0.88	0.88	0.88	0.83	0.80	0.79	0.94	0.68
JPN.HFOL	0.46	0.46	0.46	0.46	0.46	0.46	0.46	0.46	0.46
JPN.COKE	0.12	0.12	0.09	0.14	0.12	0.12	0.12	0.12	0.12
JPN.OTHP	0.69	0.69	0.69	0.69	0.69	0.69	0.69	0.69	0.69
ANZ.RGAS	0.61	0.61	0.61	0.61	0.61	0.61	0.61	0.61	0.61
ANZ.GSLN	0.72	0.72	0.72	0.72	0.72	0.72	0.72	0.72	0.72
ANZ.DISL	0.67	0.64	0.64	0.64	0.66	0.67	0.71	0.67	0.63
ANZ.HFOL	0.47	0.47	0.47	0.47	0.47	0.47	0.47	0.47	0.47
ANZ.COKE	0.09	0.09	0.08	0.09	0.11	0.09	0.09	0.09	0.09
ANZ.OTHP	0.41	0.41	0.41	0.41	0.41	0.41	0.41	0.41	0.41
EUR.RGAS	0.58	0.58	0.58	0.58	0.58	0.58	0.58	0.58	0.58
EUR.GSLN	0.68	0.68	0.68	0.68	0.68	0.68	0.68	0.68	0.68
EUR.DISL	0.56	0.54	0.54	0.54	0.55	0.56	0.67	0.63	0.39
EUR.HFOL	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29
EUR.COKE	0.12	0.12	0.09	0.11	0.16	0.12	0.12	0.12	0.12
EUR.OTHP	0.49	0.49	0.49	0.49	0.49	0.49	0.49	0.49	0.49
EET.RGAS	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60
EET.GSLN	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70
EET.DISL	0.59	0.56	0.56	0.56	0.58	0.59	0.68	0.64	0.45
EET.HFOL	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21
EET.COKE	0.07	0.07	0.07	0.07	0.08	0.07	0.07	0.07	0.07
EET.OTHP	0.48	0.48	0.48	0.48	0.48	0.48	0.48	0.48	0.48
FSU.RGAS	0.54	0.54	0.54	0.54	0.54	0.54	0.54	0.54	0.54
FSU.GSLN	0.63	0.63	0.63	0.63	0.63	0.63	0.63	0.63	0.63
FSU.DISL	0.53	0.51	0.51	0.51	0.52	0.53	0.61	0.57	0.40
FSU.HFOL	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19
FSU.COKE	0.07	0.07	0.06	0.07	0.07	0.07	0.07	0.07	0.07
FSU.OTHP	0.33	0.33	0.33	0.33	0.33	0.33	0.33	0.33	0.33
ASI.RGAS	0.62	0.62	0.62	0.62	0.62	0.62	0.62	0.62	0.62
ASI.GSLN	0.73	0.73	0.73	0.73	0.73	0.73	0.73	0.73	0.73
ASI.DISL	0.56	0.53	0.53	0.53	0.55	0.56	0.60	0.56	0.51

Region.Fuel	AGRI	ROIL	ELEC	EINT	OTHR	SERV	TRAN	HH-TRAN	HH-RESID
ASI.HFOL	0.41	0.41	0.41	0.41	0.41	0.41	0.41	0.41	0.41
ASI.COKE	0.11	0.11	0.09	0.10	0.14	0.11	0.11	0.11	0.11
ASI.OTHP	0.55	0.55	0.55	0.55	0.55	0.55	0.55	0.55	0.55
CHN.RGAS	0.41	0.41	0.41	0.41	0.41	0.41	0.41	0.41	0.41
CHN.GSLN	0.48	0.48	0.48	0.48	0.48	0.48	0.48	0.48	0.48
CHN.DISL	0.48	0.46	0.46	0.46	0.47	0.48	0.51	0.48	0.45
CHN.HFOL	0.33	0.29	0.29	0.29	0.29	0.29	0.33	0.33	0.33
CHN.COKE	0.11	0.11	0.09	0.10	0.14	0.11	0.11	0.11	0.11
CHN.OTHP	0.38	0.38	0.38	0.38	0.38	0.38	0.38	0.38	0.38
IND.RGAS	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98
IND.GSLN	1.15	1.15	1.15	1.15	1.15	1.15	1.15	1.15	1.15
IND.DISL	0.40	0.45	0.45	0.45	0.42	0.40	0.55	0.54	0.11
IND.HFOL	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30
IND.COKE	0.11	0.11	0.09	0.10	0.14	0.11	0.11	0.11	0.11
IND.OTHP	0.84	0.84	0.84	0.84	0.84	0.84	0.84	0.84	0.84
IDZ.RGAS	0.38	0.38	0.38	0.38	0.38	0.38	0.38	0.38	0.38
IDZ.GSLN	0.45	0.45	0.45	0.45	0.45	0.45	0.45	0.45	0.45
IDZ.DISL	0.20	0.23	0.23	0.23	0.21	0.20	0.23	0.22	0.15
IDZ.HFOL	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13
IDZ.COKE	0.08	0.08	0.07	0.08	0.08	0.08	0.08	0.08	0.08
IDZ.OTHP	0.32	0.32	0.32	0.32	0.32	0.32	0.32	0.32	0.32
AFR.RGAS	0.57	0.57	0.57	0.57	0.57	0.57	0.57	0.57	0.57
AFR.GSLN	0.67	0.67	0.67	0.67	0.67	0.67	0.67	0.67	0.67
AFR.DISL	0.55	0.45	0.45	0.45	0.42	0.40	0.55	0.54	0.11
AFR.HFOL	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40
AFR.COKE	0.07	0.07	0.08	0.08	0.07	0.07	0.07	0.07	0.07
AFR.OTHP	0.53	0.53	0.53	0.53	0.53	0.53	0.53	0.53	0.53
MES.RGAS	0.49	0.49	0.49	0.49	0.49	0.49	0.49	0.49	0.49
MES.GSLN	0.57	0.57	0.57	0.57	0.57	0.57	0.57	0.57	0.57
MES.DISL	0.41	0.40	0.40	0.40	0.40	0.40	0.48	0.45	0.26
MES.HFOL	0.23	0.22	0.22	0.22	0.22	0.22	0.23	0.23	0.23
MES.COKE	0.07	0.07	0.06	0.07	0.09	0.07	0.07	0.07	0.07
MES.OTHP	0.41	0.41	0.41	0.41	0.41	0.41	0.41	0.41	0.41
LAM.RGAS	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70
LAM.GSLN	0.82	0.82	0.82	0.82	0.82	0.82	0.82	0.82	0.82
LAM.DISL	0.43	0.41	0.41	0.41	0.42	0.43	0.63	0.59	0.05
LAM.HFOL	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16
LAM.COKE	0.07	0.04	0.08	0.10	0.04	0.07	0.07	0.07	0.07
LAM.OTHP	0.54	0.54	0.54	0.54	0.54	0.54	0.54	0.54	0.54
ROW.RGAS	0.59	0.59	0.59	0.59	0.59	0.59	0.59	0.59	0.59
ROW.GSLN	0.69	0.69	0.69	0.69	0.69	0.69	0.69	0.69	0.69
ROW.DISL	0.51	0.48	0.48	0.48	0.48	0.48	0.59	0.56	0.30
ROW.HFOL	0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.26
ROW.COKE	0.08	0.07	0.07	0.08	0.08	0.08	0.08	0.08	0.08
ROW.OTHP	0.42	0.42	0.42	0.42	0.42	0.42	0.42	0.42	0.42

APPENDIX 2. NEW BACKSTOP REFINING TECHNOLOGIES

Coal Gasification

Assumptions:

25 years of plant life
Plant has 1 Mt per year capacity
Coal price at **$1.5/MMBtu**
Heavy fuel oil price at **$18/bbl**
Petroleum coke price at **$0.9/MMBtu**
Capital charge: **16%**
Efficiency of gasification process: **75%**
Annual operational expenditures (OPEX) are assumed to be **3.5%** of capital expenditures (CAPEX)
Average production cost of natural gas: **$2/MMBtu in 2000**

Table A2.A. Production cost of synthetic gas.

Feed type	**CAPEX** ($M)	**CAPEX** ($M/y)	**OPEX** ($M/y)	**Fuel Cost** ($M/y)	**Total Cost** ($M/y)	**Production** (Mtoe/y)	**Production Cost** ($/toe)	**Production Cost** ($/MMBtu)	**Mark-up over natural gas**
COAL	600	27.84	75	44.04	*146.88*	0.54	272	**6.86**	**3.43**
HFOL	600	27.84	75	118.8	*221.64*	0.72	308	**7.76**	**3.88**
COKE	600	27.84	75	26.43	*129.27*	0.555	233	**5.87**	**2.94**

Residue Upgrading

Assumptions:

40 years of plant life for refinery, **25 years** for upgrading unit
Crude price at **$20/bbl**
Capital charge: **16%**
OPEX is **3.5%** of CAPEX
Average 1997 global energy input price for refineries (imported electricity and natural gas, oil products own-consumption and imports) is approximately **$4/MMBtu** (based on 60% natural gas input at $4/MMBtu, 35% heavy fuel at $18/bbl, and 5% electricity at 5cts/MWh).

Table A2.B. Total cost of crude oil processing for different refinery configurations.

Refinery configurations	**CAPEX**		**OPEX**		**FEED**	**Efficiency**	**ENERGY**	**ENERGY**	**Cost**	***Cost*** $/t
	$M/yr	$/t[43]	$M/yr	$/t	$M/yr		Mtoe/yr	$M/yr	$M/yr	
Simple (10Mt)	99	10	22	2.2	1460	0.96	0.47	41	1623	**162**
+FCC (1.6Mt)	170	17	37	3.7	1460	0.94	0.60	53	1720	**172**
+HCU (1.3Mt)	144	14.4	32	3.2	1460	0.94	0.61	54	1690	**169**
+FCC+HCU	207	20.7	45	4.5	1460	0.93	0.79	70	1782	**178**

[43] Cost per ton of processed crude oil.

Table A2.C1. Total cost of residue upgrading for different upgrading configurations

Upgrading configurations	CAPEX		OPEX		FEED	Efficiency	ENERGY	ENERGY	*Cost*	*Cost* $/t
	$M/yr	$/t [44]	$M/yr	$/t	$M/yr		Mtoe/yr	$M/yr	$M/yr	
ARDS (1.2Mt) **+RFCC** (1Mt)	75	62.8	17	13.7	143	0.82	0.25	22	258	**214**
Hydroconversion (1.2Mt)	72	60	16	13.1	143	0.85	0.20	18	248	**207**
FCC (2.6Mt) **+DCU** (1.2Mt)	95	28.1	21	6.1	400	0.85	0.57	51	566	**168**
ARDS (5.7Mt) **+RFCC** (4.74Mt)*	179	31.6	39	6.9	672	0.82	1.19	106	996	**176**
FCC (4.4Mt) **+DCU** (2Mt)*	127	22.5	28	4.9	672	0.85	0.96	85	912	**161**

* After calibration of capacity

Table A2.C2. Total cost of residue upgrading for different upgrading configurations (estimation from source 2).

Upgrading configurations	CAPEX + OPEX		FEED $M/yr	Efficiency	ENERGY Mtoe/yr	ENERGY $M/yr	*Cost* $M/yr	*Cost* $/t
	$M/yr	$/t [44]						
FCC+DCU (5.7Mt total capacity)	136	24.1	672	0.85	0.96	85	893	**158**
ARDS+RFCC (5.7Mt capacity)	218	38.5	672	0.82	1.19	106	996	**176**

Table A2.D. Total revenue for different refinery and upgrading configurations.

	Typical Yield (Mtoe)									
Configuration	LPG	Naphtha	Gasoline	Kerosene	Diesel	Heavy Fuel	Other	Coke	*Revenue* $M/yr	*Revenue* $/t [45]
Simple (10Mt)	0.24	0.23	1.80	0.84	3.62	2.05	0.97		1881	**188**
+FCC (1.6Mt)	0.38	0.59	2.77	0.99	4.19	0.75	0.99		2228	**223**
+HCU (1.3Mt)	0.32	0.78	2.33	0.99	4.42	0.88	0.94		2197	**220**
+FCC+HCU	0.30	0.72	2.62	0.84	4.72	0.31	0.96		2216	**222**
ARDS+RFCC (5.7Mt)	0.83	0.06	2.30		1.62	0.19			1127	**199**
FCC+DCU (5.7Mt)	0.83	0.22	1.89		0.95	0.31		0.07	939	**166**
1997 Price ($/toe)	*199*	*219*	*260*	*226*	*203*	*125*	*136*	30		

[44] Cost per ton of processed residue.

[45] Revenue is per ton of processed crude oil if refinery full configuration, or per ton of processed residue if upgrading technology.

APPENDIX 3. NON-CONVETIONAL OILS

Assumptions:

For bitumen production, we assume that non-gas OPEX is 80% labor, 7% gas-related liquids, 5% electricity, 6% services, and 2% energy-intensive inputs (steel, etc.).

For bitumen upgrading, we assume that non-gas OPEX is 72% labor, 8% gas-related liquids, 6% heavy fuel oil, 6% electricity, 6% services, and 2% energy-intensive inputs.

For both technologies, capital input is 90% of capital expenditure and capital maintenance. The remaining 10% are energy-intensive inputs.

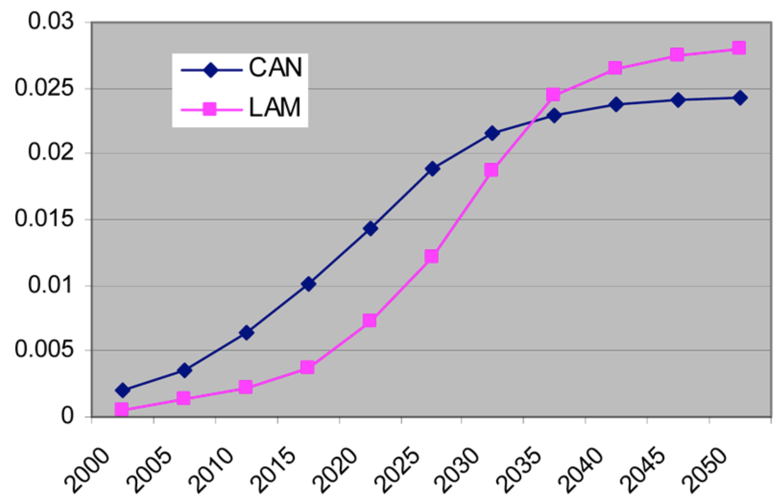

Figure A3.1. Fixed factor resource for bitumen upgrading.

Table A3.A. Non-conventional oils production capacity forecast* (EJ).

	2000	2005	2010	2015	2020
Canada	1.4	2.4	4.6	6.8	9.6
Venezuela	0.4	1.2	1.4	3.0	6.0

* Based on private conversations with experts at Cambridge Energy Research Associates.

Table A3.B. Atmospheric residue yield in EU Refineries** (average, mix of Brent, Nigerian Forcados, Iranian Light, Kuwait).

	1995	2000	2005	2010	2015	2020
% wt.	42.4	42.4	43	43.5	44.1	44.8
% increase per 5 year period		0	1.42	1.16	1.38	1.59

** Estimates derived from CONCAWE (1999).

Table A3.C. Production capacity, 1995-2010 (thousand barrels per day)[†].

NGLs	1995	2000	2005	2010
USA	395	460	500	500
CAN	160	180	200	200
MEX	85	120	140	150
ANZ	100	145	225	300
JPN	0	0	0	0
EUR	492	710	845	935
EET	N/A	N/A	N/A	N/A
FSU	408	545	820	1200
ASI	95	220	395	540
CHN	42	60	90	125
IND	10	25	40	50
IDZ	155	110	130	175
AFR	635	845	1095	1390
MES	309	722	1487	2410
LAM	94	180	370	500
ROW	N/A	N/A	N/A	N/A
Condensates	**1995**	**2000**	**2005**	**2010**
USA	1800	1900	2000	1700
CAN	430	560	650	750
MEX	390	450	500	550
ANZ	70	85	90	200
JPN	0	0	0	0
EUR	410	445	495	515
EET	31	35	40	45
FSU	350	280	350	750
ASI	73	170	260	330
CHN	0	0	50	150
IND	20	35	60	75
IDZ	100	110	130	175
AFR	215	429	635	1030
MES	1074	1303	1924	2675
LAM	238	347	482	660
ROW	N/A	N/A	N/A	N/A

[†] Authors' calculations based on private conversations with experts at Cambridge Energy Research Associates.

Table A3.D. Production capacity, 1995-2010[†].

	RGAS production in 1997 (thousand barrels per day)	**Average 1995-2010 increase in RGAS production due to NGL and condensates** (%)
USA	4100	+0.01%
CAN	826	+2.33%
MEX	584	+2.06%
ANZ	286	+4.02%
EUR	1471	+10.22%
EET	100	+0.05%
FSU	504	+63.81%
ASI	479	+7.43%
CHN	337	+2.59%
IND	215	+1.50%
IDZ	278	+2.36%
AFR	1178	+30.08%
MES	2427	+16.77%
LAM	721	+1.82%

[†] Authors' calculations based on private conversations with experts at Cambridge Energy Research Associates.