Energy Technology Systems Analysis Programme

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Review of resources and trade of fossil energy resources in the TIAM model

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1 Introduction

1.1 Background

Global energy demand has been grown continuously over the last decades. Especially, in emerging economies as China, India or Brazil, this trend is forecasted to continue also in the future. Oil, gas and coal have been the dominant primary energy carriers until today. The reserves and resources of these fossil fuels are, however, finite. Also, the CO_2 emissions from burning fossil fuels contribute to the greenhouse gas effect in the atmosphere. Since the fossil resources, especially in the case of conventional oil and gas, are not evenly distributed in the world, the necessary infrastructure to transport the fossil fuels from the resource site to the consumption region is a further aspect in the usage of these energy carriers.

To analyze the future extraction of fossil fuels as well as their trade between world regions, assumptions on the amount of fossil reserves and resources, their extraction costs and the options and costs are critical input assumptions in a global energy system model as the TIAM model.

1.2 Organization of the report

After a definition of some resource terms used throughout this report, at first, the chosen reserve and resource data as well as their supply costs are discussed for the fossil energy sources coal, oil and gas. Then, the energy trade structure between the world regions and the assumptions on the transport costs for the different energy carriers are presented. In a scenario analysis the new input data for fossil resources and the introduced trade infrastructure are being tested. In the appendix, technical information, on how the input data are organized in Excel sheets, is given.

2 Definitions

2.1 Reserves and resources

The quantities of fossil accumulations in the reservoir can be distinguished in *reserves* and *resources*.

Reserves are the estimated quantities of oil and gas of a specified date, expected to be commercially recovered from known accumulations under prevailing economic conditions, operating practices, and government regulations. Reserves are generally classified with respect to the certainty of their existence as proved, probable, or possible. Alternatively, one can quote reserves as 95 % likely (P95), 50 % likely (P50) or 5 % likely (P5).

Resources are demonstrated quantities that cannot be recovered at current prices with current technology but might be recoverable in the future, as well as quantities that are geologically possible but not demonstrated. In the case of oil and gas, only recoverable amounts are considered. For coal this term is used for all resources in-place. Recoverable resources are the part of the resource amount, which can be produced with the present extraction technologies. The distinction between reserves and resources is not static. Since the definitions depend on the economic conditions and available technology options it might evolve over time.

2.2 Conventional and unconventional hydrocarbons

Natural gas and oil are typically distinguished in conventional and unconventional deposits. This differentiation is mainly determined by the geological reservoir conditions and by the technology required to extract the hydrocarbons from the reservoir. While for conventional gas and oil existing extraction technologies can be used, unconventional oil and gas reservoirs typically require new and often more costly extraction technologies.

In the case of oil, conventional oil is defined as oil produced by so-called primary or secondary recovery methods. During the primary recovery phase of an oil field, the oil is transported due to the reservoir pressure itself to the wellhead, while secondary recovery methods maintain the reservoir pressure and thus the production by the injection of water and natural gas. Oil produced by so-called tertiary or enhanced recovery methods, which are commonly referred to as recovery methods involving substances not present in the reservoir, e.g. steam, CO_2 or chemicals, is by this definition already unconventional oil. Since enhanced recovery methods are applied to oil fields, which have been exploited before by conventional recovery methods, enhanced recovery methods are presented here within the context of the conventional resource base. Oil (tar) sands, extra-heavy oil and shale oil are commonly referred to as unconventional oil.

Natural gas which can be extracted through its reservoir pressure is generally considered as conventional gas. Natural gas recovered by the injection of CO_2 would fall in the category of unconventional gas, but is discussed here in the section of conventional gas. Coal-bed methane, tight gas, aquifer gas and gas hydrates are considered here as unconventional gas categories.

3 Global fossil resource base

In the following the assumptions on the reserves and resource data and the supply costs of the fossil energy carriers coal, oil and natural gas are discussed.

3.1 Coal

Coal consumption accounted for 28 % (116 EJ) of global primary energy supply of 412 EJ in 2004, the second largest share after oil with 38 % (/BP 2005/). According to its composition (carbon, ashes, sulfur, volatile matter, water) coal can be classified in hard coal (anthracite, bituminous coal, sub-bituminous coal), lignite and peat. Hard coal is used as steam coal for electricity, heat and steam generation and as coking coal in the steel industry (16.5-33 MJ/kg). Lignite is nearly exclusively used for electricity and heat generation in power plants near the mine (up to a maximum of 100 km), since due to its low energy/high water content (6.7-16.5 MJ/kg /BGR 2003/), the transport of lignite across long distances is not economic.

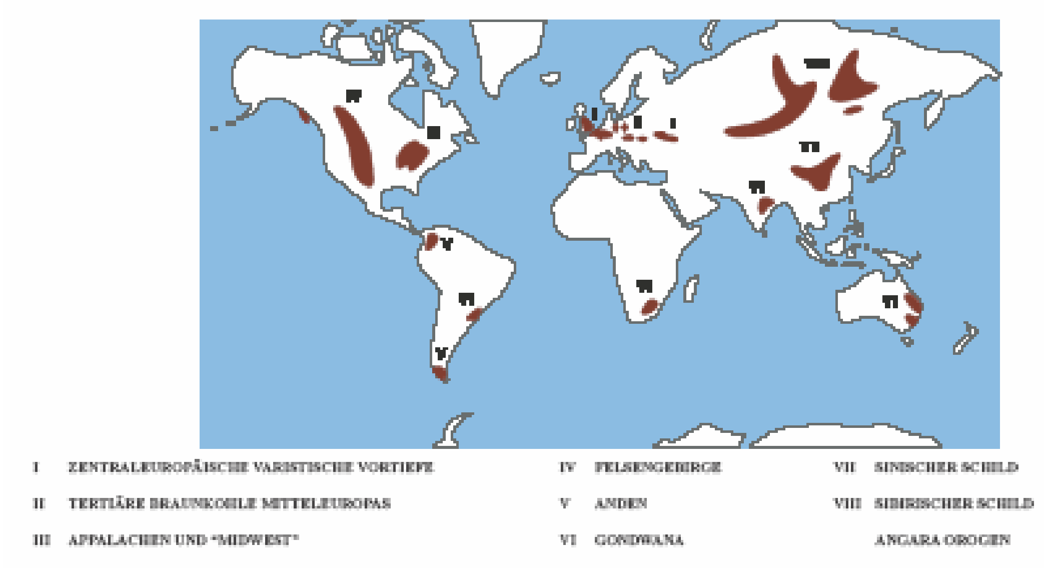

Figure 1: Location of major coal deposits in the world (/BGR 2003/)

3.1.1 Lignite

Reserves and resources

Global lignite reserves are around 2022 EJ, while resources are estimated to be around 8922 EJ. Large lignite deposits are located in the USA, Russia, China, Kazakhstan, Germany and Australia. Largest producer in 2004 was Germany with 182 Mt of lignite, followed by Russia, USA, Greece and Australia with 74, 70, 68 and 67 Mt, respectively. The global production comprised 902 Mt in 2004. The geographic distribution of the lignite reserves and resources on the world regions is given in Table 1. Lignite reserves and resources are modeled in the TIAM model each with a single extraction process.

Table 1: Global lignite reserves and resources by world region at the beginning of 1998 (/BGR 2006/)

	AFR	AUS	CAN	CHI	CSA	EEU	FSU	IND	JPN	MEA	MEX	ODA	SKO	USA	WEU	Total
Reserves [EJ]	0	368	31	183	51	292	188	339	0	30	3	88	0	328	121	**2022**
Resources [EJ]	2	427	29	839	198	542	1917	38	0	78	0	215	0	3826	809	**8922**
Average heating value [MJ/kg]	8.79 - 9.67	9.67 - 13.19	11.72	11.72	8.79 - 9.67	7.33 - 14.65	8.79 - 13.19	9.67	9.67	8.79 - 9.67	8.79	8.79 - 9.67	8.79	14.65	5.57 - 17.0	**5.57 - 17.0**

Supply costs

Supply cost data for lignite are scarce in the literature (/BGR 2003/, /WEC 2000/, /NEA 2005/). Here data cited in the mentioned references for some main producing countries have been used as approximation for the costs in the world regions (Table 2). Lowest supply costs are found in Russia (FSU) and Indonesia (ODA) with 0.3 $/GJ, whereas costs in the upper range are observed in Australia (0.79 $/GJ), CSA (0.69 $/GJ), EEU (0.66 $/GJ) and WEU (0.55 $/GJ).

Table 2: Supply costs for lignite in the world regions (/BGR 2003/, /WEC 2000/, /NEA 2005/)

$/GJ	AFR	AUS	CAN	CHI	CSA	EEU	FSU	IND	JPN	MEA	MEX	ODA	SKO	USA	WEU
Reserves	0.49	0.79	0.36	0.36	0.69	0.59	0.30	0.36	0.93	3.47	0.36	0.30	0.93	0.36	0.55
Resources	4.70	4.70	4.70	4.70	4.70	4.70	4.70	4.70	4.70	4.70	4.70	4.70	4.70	4.70	4.70

3.1.2 Hard coal

Reserves and resources

Global hard coal reserves have been around 19342 EJ at the end of 1997, while further resources are assessed to be ca. 96201 EJ. Large amounts of hard coal can be found in South Africa, Australia, China, the Former Soviet Union, India and the USA (Table 3). In 2004, 4661 Mt of hard coal have been produced on a global level with China (1956 Mt), USA (902 Mt), India (369 Mt), Australia (286 Mt), South Africa (243 Mt), Russia (208 Mt) being the largest producing countries. 3.4 Mt have been used for electricity generation, 0.7 Mt for heat and steam generation and 0.6 Mt for steel production. The static lifetime[1] (ratio of reserves to production) of known coal reserves was hence 137 years, including additionally the resources the static lifetime increases to 840 years. As for lignite hard coal reserves and resources are modeled each by a single extraction process.

Table 3: Global hard coal reserves and resources by world region at the beginning of 1998 (/BGR 2006/)

EJ	AFR	AUS	CAN	CHI	CSA	EEU	FSU	IND	JPN	MEA	MEX	ODA	SKO	USA	WEU	Total
Reserves [EJ]	1243	1605	90	2523	370	298	4597	2196	9	35	22	170	2	6135	46	**19342**
Resources [EJ]	2989	3650	1193	21275	847	1317	45410	114	3872	119	48	5197	0	9864	306	**96201**
Average heating value [MJ/kg]	22.86 - 24.91	23.45 - 26.38	27.84	21.1	20.52 - 27.55	17.58 - 24.91	19.34 - 23.45	20.8	22.8	23.45 - 26.67	23.5	19.05 - 23.45	23.5	25.2	20.52 - 27.55	**19.05 - 27.55**

Supply costs

The average supply costs for hard coal in the different world regions are summarized in Table 4. The supply costs for coal mainly depend on the depth of coal seam (surface or deep mining) and the transport distance to local consumers or export ports. The supply costs generally include the production costs at the mine, domestic transportation costs from the mine to the export harbor as well as harbor costs. Exemptions are the rail transport costs for coal exports from the USA to Canada, which have been added on the coal trade process between the regions (15 $/t), and the rail transport in the FSU from the mine to the harbor, which have also been added to the different export processes for Russian coal (17 $/t). The latter has been done to more easily change the assumed costs for Russian rail transport costs, since current Russian freight tariffs (4 $/(t*1000 km)) are quite low compared to other countries (10 $/(t*1000 km)) /Schmidt et al. 2005/.

Table 4: Supply costs for hard coal in the world regions (/Ball et al. 2003/, /BGR 2003/, /RWE 2005/, /Rogner 1997/, /Schmidt et al. 2005/)

$/GJ	AFR	AUS	CAN	CHI	CSA	EEU	FSU	IND	JPN	MEA	MEX	ODA	SKO	USA	WEU
Reserves	1.03	1.06	1.87	1.36	0.96	1.53	0.86	1.60	3.65	4.00	1.87	1.18	3.65	1.31	3.65
Resources	1.37	1.40	2.20	1.70	1.30	1.87	1.20	1.94	4.01	4.34	2.20	1.53	4.01	1.66	4.01

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[1] Static lifetime is the ratio of a reserve or resource amount to its production and corresponds to the number of

Low supply costs for known reserves (around 1-1.4 $/GJ) on a global level are observed in Africa, Australia, South America and the Former Soviet Union, while the highest costs (3.7 $/GJ) occur due to the depth of the coal mines in Western Europe, South Korea and Japan. For the supply costs of the resources additional costs of 0.34 $/GJ have been assumed compared to the costs of the reserves.

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years the resource can be used under the assumption that the production level is constant.

3.2 Natural gas

Natural gas consumption continually increased on a global level. From 27 EJ in 1965 its consumption nearly quadrupled to 101 EJ in 2004 (Figure 2). Until the first oil crisis in the 70s of the last century natural gas was only considered as a by-product of oil production, being often flared at the oil field. Despite higher transportation costs compared to oil, natural gas consumption has benefited from increase in oil prices and in recent years from its lower CO_2 emissions compared to coal and oil.

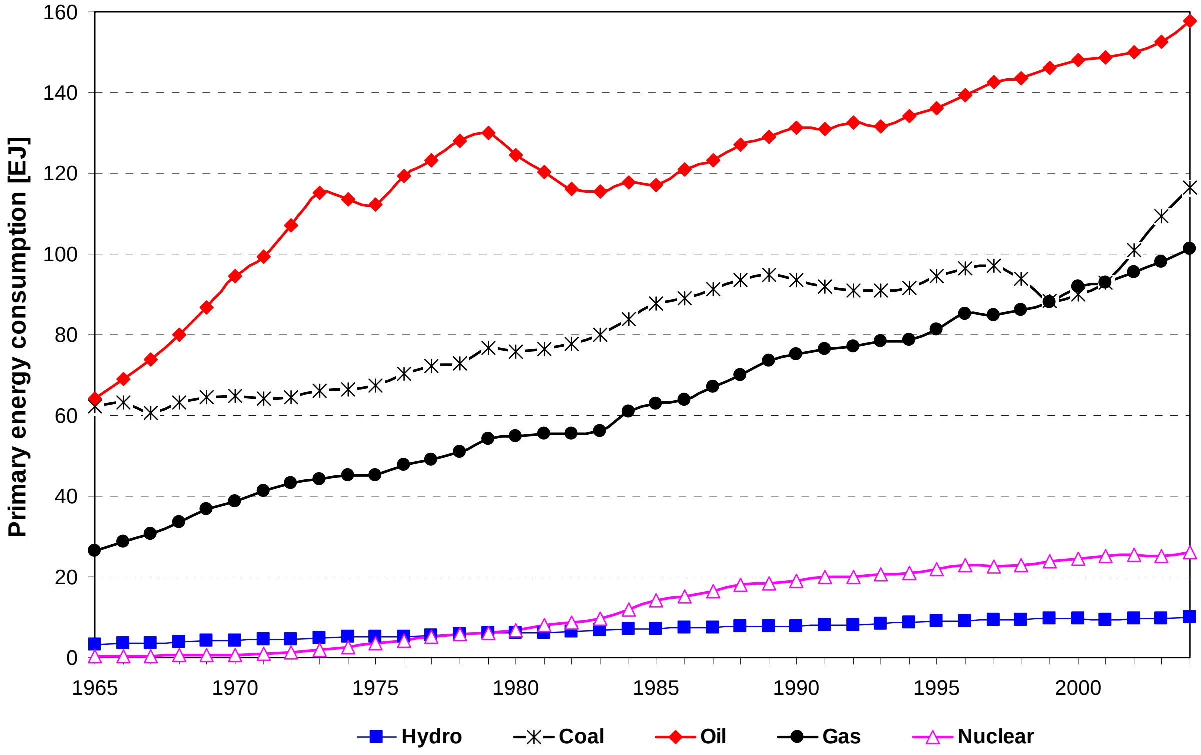


Figure 2: Historic development of primary energy carriers (/BP 2005/)

The modeling of the gas supply in the TIAM model is shown in Figure 3. Conventional gas is divided in the categories Recoverable reserves, Enhanced gas recovery (EGR), New discoveries and Additional occurencies/Not connected. Each category is depicted by three extraction processes representing different extraction cost steps. Similarly, the unconventional gas resource categories (Coal-bed methane, Tight gas, Aquifer gas, Gas hydrates) have been modeled. For the world regions containing OPEC member countries, the fossil fuel supply and further fuel processing (e.g. gas plants, refineries) is divided into the two sub-regions OPEC and Non-OPEC.

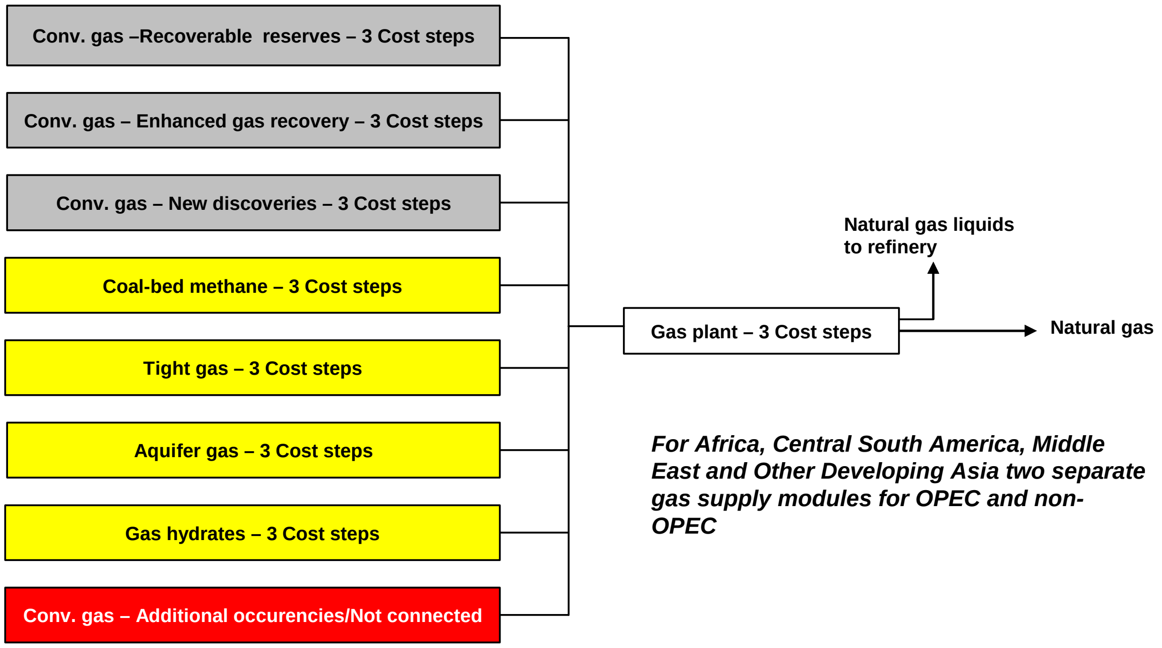
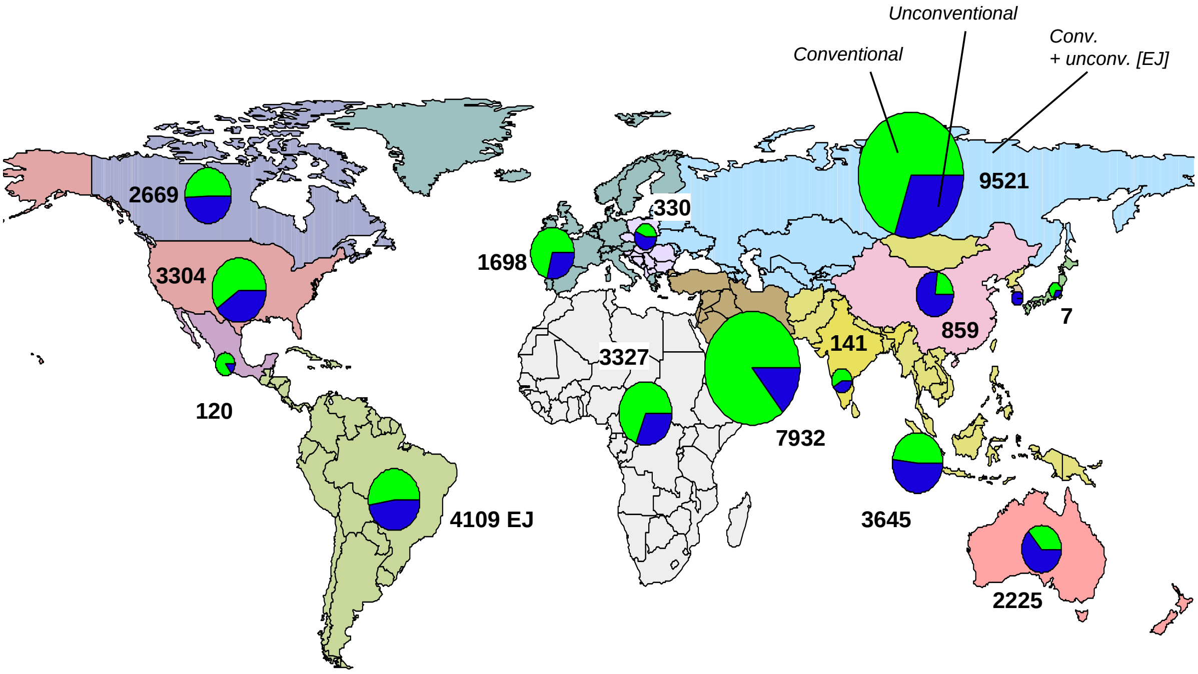


Figure 3: Gas supply module in the TIAM model

An overview on the global distribution of conventional and unconventional gas deposits is given in Figure 4. Large amounts of conventional natural gas are located in the Middle East, the Former Soviet Union and Africa. Unconventional gas resources are more equally distributed, in addition to the regions with large conventional gas resources, significant amounts of unconventional gas can also be found in Asia, Australia and North America. In the following the resource situation for conventional and unconventional gas is discussed in more detail.



Conventional [EJ]		Unconventional reserves + resources [EJ]			Total [EJ]	Gas hydrates resources [EJ]	Gas production 2004 [EJ]
Reserves	Resources	Coal-bed methane	Tight gas	Aquifer gas			
12673	5256	2827	1694	17441	39890	47400	88

Figure 4: Distribution of conventional and unconventional gas deposits (/BGR 2003/, /BGR 2006/, /WEC 2004/, /USGS 2000/, /BP 2005/)

3.2.1 Conventional natural gas

Total amount of reserves and resources of conventional gas have been estimated to be at a level of 17568 EJ. These amounts are geographically uneven distributed on the world. The largest amounts of conventional gas are located with 5467 EJ (31 %) in the Middle East and 5426 EJ (31 %) in Russia and the former Soviet Republics Azerbaijan, Kazakhstan, Turkmenistan, Ukraine and Uzbekistan. These estimates for conventional natural gas include proven recoverable gas reserves, estimated amounts obtained through enhanced gas recovery from past, existing and future gas fields as well as so far undiscovered gas resources, of which the existence can however be postulated from geological conditions with some degree of probability. The quantities of these three categories are shown in Table 5 for the different world regions.

Table 5: Regional distribution of conventional gas reserves and resources at the beginning of 1998 (/WEC 2004/, /USGS 2000/)

EJ	AFR	AUS	CAN	CHI	CSA	EEU	FSU	IND	JPN	MEA	MEX	ODA	SKO	USA	WEU	Total
Reserves	584	152	413	65	285	21	2114	32	2	2597	22	290	0	296	245	**7118**
EGR	377	101	312	48	205	47	1623	23	3	1603	32	213	0	697	270	**5554**
Undisc. Resources	365	112	25	87	478	14	1815	31	0	1327	50	256	0	297	399	**5256**
Total	**1326**	**365**	**749**	**200**	**968**	**82**	**5552**	**86**	**5**	**5527**	**104**	**759**	**0**	**1291**	**914**	**17928**

Recoverable Reserves

Reserve data for proven recoverable reserves are based on the “2004 Survey of World Energy Resources” of the World Energy Council (/WEC 2004/). Global reserves of recoverable reserves add up to 7118 EJ at the beginning of 1998. On a country level Russia is the country has with 1686 EJ the highest gas reserves, Iran is second with 953 EJ. Together both countries account for 39 % of the global proven gas reserves. Based on the natural gas production in 2004 of 101 EJ, the static lifetime of gas reserves was 64 years in that year.

Enhanced natural gas recovery (EGR)

Injection of carbon dioxide (CO_2) is a proven method to enhance the recovery from oil fields (enhanced oil recovery – EOR). Enhancing natural gas recovery (EGR) by injecting CO_2 has been until recently not utilized on industrial scale. In 2004, a CO_2 capture and storage project at the In Salah gas fields in Algeria started /Wright 2006/. There, CO_2 is separated at a gas processing plant from the extracted gas and reinjected in the gas field to store the CO2 in the pore space of the gas field. At the same time the replacement of gas by CO_2 as well as the pressurization increases the recovery of the gas field. The operators of the project stress, however, that the injection of the CO_2 offers currently no economic benefits compared to venting of the CO_2, but causes additional costs of ca. 6 \$/t CO_2.

The global potential gas supply by enhanced gas recovery (EGR) is determined by estimating how much gas can be additionally extracted from abandoned, existing or future gas field, if the recovery rate is increased. As recovery rate from conventional gas production without EGR a value of 50 % is assumed, while for EGR it is assumed that the recovery rate can be increased by 30 % yielding an overall recovery rate of 80 % (/Nakicenovic et al. 2000/). To derive the contribution of enhanced gas recovery from past production, it is assumed that the cumulative production has been produced with a recovery factor of 50 %. Thus, the amount-in-place can be calculated, which then yields the additional gas amount from EGR by applying the additional recovery factor of 30 %. In a similar way, the effect of EGR for the future gas production can be estimated from the remaining recoverable reserves by determining the corresponding amount of gas-in-place. Thus, the total gas potential from EGR amounts to estimated 5554 EJ.

Undiscovered resources

Estimates of mean undiscovered gas resources, of which the existence can be deduced from geological information, on country level are based on the “Geological Survey World Petroleum Assessment 2000” of the U.S. Geological Survey (/USGS 2000/). Total mean undiscovered gas resources are estimated to be around 5256 EJ.

Natural gas liquids

Raw natural gas obtained from the well head commonly exists in mixtures with other hydrocarbons; principally ethane, propane, butane, and pentanes. In addition, raw gas contains water vapor, hydrogen sulfide (H_2S), carbon dioxide, helium, nitrogen, and other compounds. Natural gas processing consists of separating all of the various hydrocarbons and fluids from the pure natural gas, to produce dry natural gas. In fact, associated hydrocarbons, known as natural gas liquids (NGLs)[2] can be very valuable by-products of natural gas processing. These NGLs are sold separately and have a variety of different uses; including enhancing oil recovery in oil wells, providing raw materials for oil refineries or petrochemical plants, and as sources of energy.

The NGL and natural gas dry gas production by world region for the years 2000 and 2005 are given in Table 6. Based on these data, the ratio of NGL to dry gas production has been determined. The value of 2005 has been extrapolated as a constant for the future time periods.

Specific investment costs for a gas processing plants are around 1.9 Mio. $/(PJ/a) of dry gas capacity (average based various issues of the worldwide construction updates in the Oil & Gas Journal).

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[2] Natural gas liquids can be further classified according to their vapour pressures as low (gas condensate); intermediate (natural gasoline) and high (liquefied petroleum gas) vapour pressure. Natural gas liquids include

Table 6: NGL and dry gas production by world region (/OGJ 2000/, /OGJ 2005a/, /BP 2005/, /BP 2006/)

Region	**2000**			**2005**		
	NGL	**Natural gas**	**NGL/Gas**	**NGL**	**Natural gas**	**NGL/Gas**
	PJ	PJ	PJ_{NGL}/PJ_{Gas}	PJ	PJ	PJ_{NGL}/PJ_{Gas}
AFR	699	4773	0.146	917	5468	0.168
AUS	454	1377	0.329	655	1461	0.448
CAN	2748	6904	0.398	1563	6887	0.227
CHI	0	1026	0.000	0	1537	0.000
CSA	849	3684	0.231	780	4869	0.160
EEU	32	657	0.049	37	662	0.056
FSU	441	25406	0.017	516	27926	0.018
IND	294	1013	0.290	357	1110	0.322
JPN	0	0	-	0	0	-
MEA	3050	7787	0.392	4080	10547	0.387
MEX	817	1348	0.606	752	1398	0.538
ODA	427	6866	0.062	468	8068	0.058
SKO	0	0	-	0	0	-
USA	3953	20746	0.191	4164	20457	0.204
WEU	215	10099	0.021	537	11032	0.049
World	**13978**	**91687**	**0.152**	**14828**	**101421**	**0.146**

The NGL amounts are typically in compilations of oil reserve included in the figures for the conventional oil resources. Complete information on NGL reserves on a country or region level is not available. Only, for some countries information on NGL reserves are shown separately in /WEC 2004/.

3.2.2 Unconventional natural gas

As unconventional gas resources coal-bed methane, tight gas, aquifer gas and gas hydrates have been considered in this analysis. Information on unconventional gas resources is highly uncertain, since so far plenty unconventional gas is available reducing the incentive to explore unconventional gas deposits. Total unconventional gas resources correspond to 69368EJ including gas hydrates (Table 7).

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propane, butane, pentane, hexane and heptane, but not methane and ethane, since these hydrocarbons need refrigeration to be liquefied.

Table 7: Regional distribution of unconventional gas resources at the end of 2002 (/BGR 2003/, /BGR 2006/)

EJ	**AFR**	**AUS**	**CAN**	**CHI**	**CSA**	**EEU**	**FSU**	**IND**	**JPN**	**MEA**	**MEX**	**ODA**	**SKO**	**USA**	**WEU**	**Total**
Coal-bed methane	22	183	246	612	20	41	1154	48	2	2	2	154	2	211	128	**2827**
Tight gas	101	20	51	46	71	12	639	8	1	399	13	76	0	178	80	**1694**
Gas hydrates	470	2348	4689	0	5636	0	27120	0	0	470	0	470	0	4689	1517	**47407**
Aquifer gas	1879	1658	1622	0	3050	195	2173	0	0	2000	0	2666	0	1622	575	**17441**
Total	**2472**	**4208**	**6609**	**658**	**8776**	**248**	**31086**	**55**	**2**	**2871**	**16**	**3366**	**2**	**6700**	**2300**	**69368**

Coal-bed methane

The gas found in many coal seams is rich in methane and often contains high proportions of carbon dioxide and nitrogen. It is still formed during the transformation of the coal. Coal therefore is the source rock of the so-called coal-bed methane gas (CBM).[3]. Coal-bed methane is produced by drilling a well in the coal seam, through high pressure artificial fractures are created in the coal seam, which is then filled with a sand-water mixture. By reducing the pressure coal-bed methane can then be produced. The depth of the coal seam should not be deeper than 2000 meters, since at higher depths due to the pressure the permeability of the coal seam will be too low for gas production /Bergen et al. 2000/. To enhance the CBM production, another gas (nitrogen or carbon dioxide) can be injected by a second well in the coal seam (enhanced coal bed methane recovery - ECBM). While N_2 reduces the partial pressure of methane and stimulates thus its release, CO_2 adsorbs more to the coal and replaces the methane. The use of CO_2 in ECBM is also discussed in the context of storing captured CO_2 in the coal seam to reduce global greenhouse gas emissions. ECBM with CO_2 is limited to coal mines that will be not mined in the future. Some pilot operations have been conducted on ECBM in the USA (CO_2, N_2), Canada (CO_2) and China (CO_2). In the case of CO_2 injection, the ratio between CO_2 injected and CBM produced is in the range of 2–4 depending on the depth /Saghafi 2002/. The temperature increase with depth reduces the adsorption of coal for CO_2. Compared to recovery factors of 20 to 60 % for CBM, the recovery factor can be increased to 90 % by ECBM with CO_2 /Bergen et al. 2000/.

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[3] Coal-bed methane is defined as gas from undeveloped coal deposits, i.e., no coal mine has been constructed, whereas gas from coal mines is called during the operation of the coal mine coal seam methane (CSM) and after abandoning the mine coalmine methane (/BGR 2003/).

Global resource amount of is estimated to be around 2827 EJ with large deposits found in regions with high coal resources, namely, the Former Soviet Union, North America, China and Australia. Global CBM production was roughly 1.5 PJ in 2001, which is nearly entirely produced in the USA (1.42 PJ) /BGR 2006/.

Tight gas

Tight gas reservoirs (also called tight formation gas when in sand stone or shale gas in clay stone) are defined as gas contained in a tight formation with its permeability of less than 0.1 milliDarcy (mD). Tight gas is already being produced in some countries of the world (USA, Canada, Europe, and China). Hydrofracturing with water-sand mixtures to increase the permeability is the main method for producing tight gas. Information on the potential of tight gas is very scarce. Therefore, in /BGR 2003/ a statistical approach has been chosen. From available information on the tight gas resources in some countries a ratio of 0.16 between tight gas resources and conventional gas resources has been assumed to derive the global tight gas resources of 1694 EJ.

Aquifer gas

Aquifer gases spread in underground waters in dissolved or dispersed (micro-bubble) state. One can distinguish geopressured gas and hydropressured gas. Due to geological aspects, the low density of the dissolved gas in the water and ecological reasons only a fraction of 10 to 25 % of this resource can be exploited. Aquifer gas is produced by pumping the water to the surface, which may cause a drawdown of the surface. Based on the groundwater resources the amount of aquifer gas resources in-place has been estimated in /BGR 2003/. It has been assumed here that 3 % of the in-place resources are recoverable leading to a global resource amount of 17441 EJ.

Gas hydrates

Gas hydrates are a crystalline mixture of water and methane being similar to the state of ice. Gas hydrates exist under high pressure and deep temperatures in permafrost areas or at the continental shelves in the sea. At the continental shelves gas hydrates have been found at water depth between 300 and 5000 meters. In permafrost areas gas hydrates are expected to exist in depths between 150 and 2000 meters. Technologies to exploit gas hydrate reservoirs are still in the research phase. Estimates in global hydrate resources differ considerably and contain a high level of uncertainty. /BGR 1999/ assumes that 47407 EJ of gas hydrates exist on- and offshore together. Due to its speculative nature gas hydrates have been excluded as resource in the modeling runs.

3.2.3 Natural gas supply costs

Cost curve for the different categories of conventional and unconventional gas reserves and resources have been derived by using a logistic function approach (/Rogner 1990/, /Rogner 1997/, /Sauner 2000/). It is assumed that the supply costs of natural gas rise as a logistic function with the cumulative amount of resources consumed. The logistic functions assumed for conventional and unconventional gas are shown in Figure 5 and Figure 6. For each of the different resource categories minimum and maximum supply costs have been estimated from a literature sources (/BGR 2003/, /Fainstein et al. 2002/, /OME 2001/, /Oostvorn 2003/, /Rogner 1997/, /Sauner 2000/). These logistic functions have been approximated by three costs steps also shown in the graphs. The resulting cost ranges for the different resource categories are summarized in Table 8, where the minimum value corresponds to the costs of the first step and the maximum value to the costs of the third step.

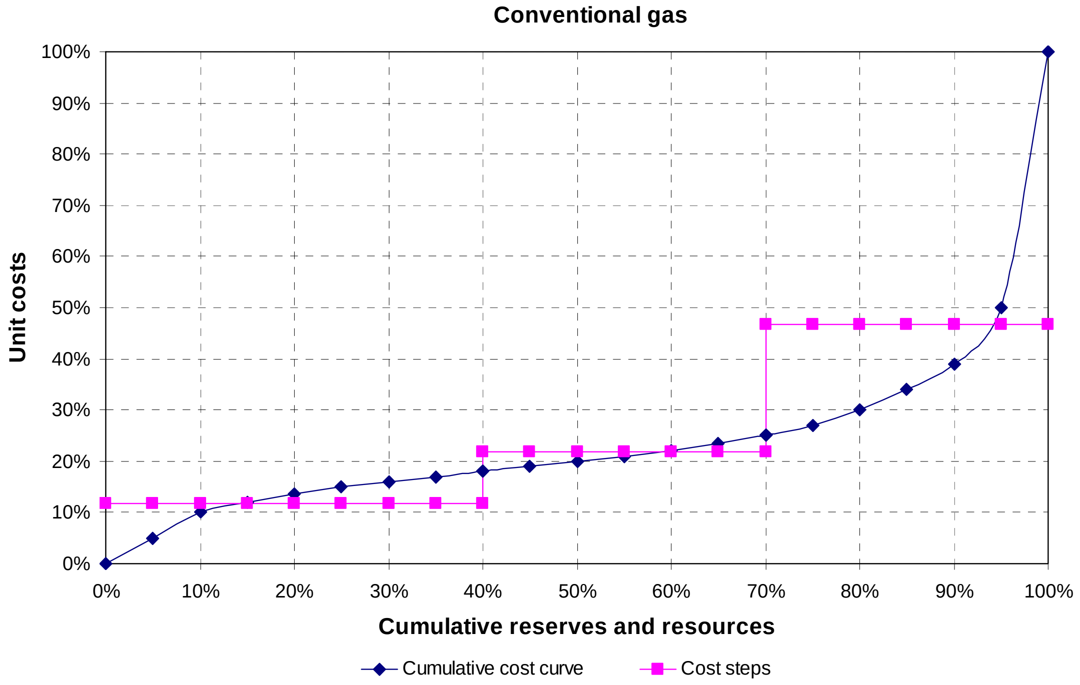

Figure 5: Cumulative cost curve for conventional gas resources (adapted from /Rogner 1990/, /Rogner 1997/, /Sauner 2000/)

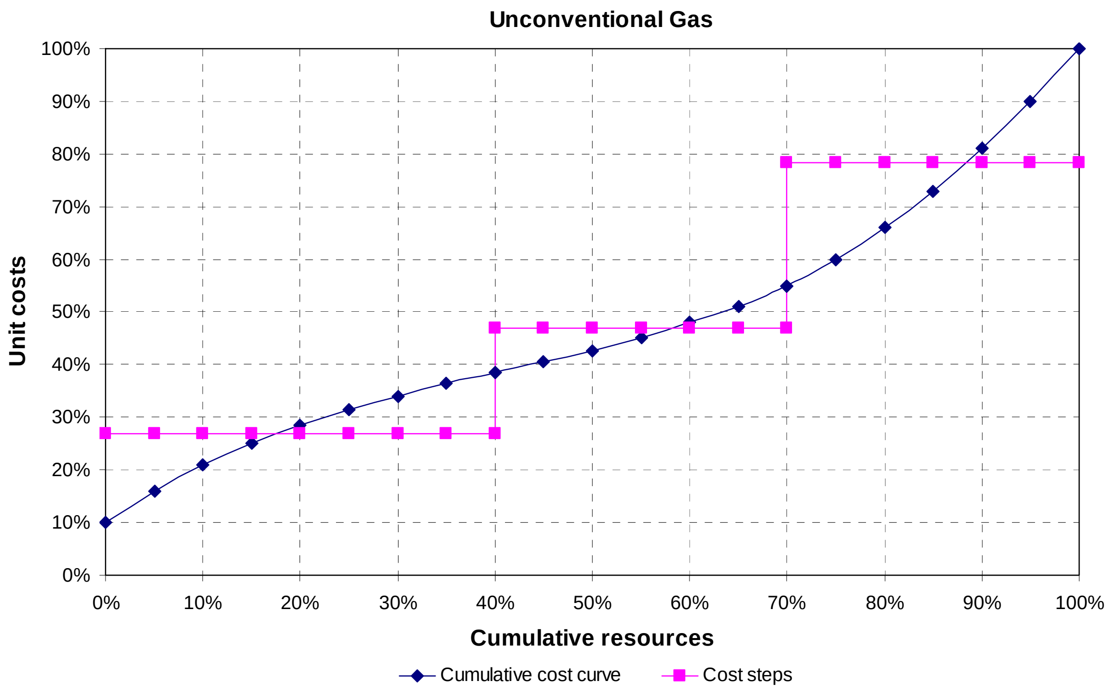

Figure 6: Cumulative cost curve for unconventional gas resources (adapted from /Rogner 1990/, /Rogner 1997/, /Sauner 2000/)

Table 8: Cost range for the different gas categories in $/GJ

$/GJ		AFR	AUS	CAN	CHI	CSA	EEU	FSU	IND	JPN	MEA	MEX	ODA	SKO	USA	WEU
Reserves	Min	0.4	1.8	1.3	0.4	0.4	0.6	0.5	0.4	0.6	0.2	1.3	0.4	0.6	1.4	0.6
	Max	0.5	2.1	1.8	0.6	0.5	1.2	0.8	0.6	1.2	0.3	1.8	0.5	1.2	1.6	1.2
EGR	Min	3.3	5.4	5.8	3.4	3.1	5.1	3.9	3.4	5.1	2.9	5.8	3.3	5.1	4.4	5.1
	Max	4.6	6.8	7.1	4.8	4.4	6.4	5.3	4.8	6.4	4.3	7.1	4.6	6.4	5.8	6.4
Undisc. Resources	Min	0.9	3.9	3.0	0.9	0.8	1.6	1.1	0.9	1.6	0.5	3.0	0.9	1.6	2.9	1.6
	Max	1.2	4.9	4.7	1.4	1.0	3.3	2.0	1.4	3.3	0.7	4.7	1.2	3.3	3.4	3.3
Coal-bed methane	Min	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1
	Max	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1
Tight gas	Min	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2
	Max	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2
Gas hydrates	Min	9.6	9.6	9.6	9.6	9.6	9.6	9.6	9.6	9.6	9.6	9.6	9.6	9.6	9.6	9.6
	Max	17.2	17.2	17.2	17.2	17.2	17.2	17.2	17.2	17.2	17.2	17.2	17.2	17.2	17.2	17.2
Aquifer gas	Min	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3
	Max	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7

The lowest supply costs occur for conventional gas resources with 0.2 $/GJ in the Middle East, followed by South America, Africa and China with 0.4 $/GJ. The highest cost (excluding gas hydrates) have been assumed for aquifer gas with 6.8-8.0 $/GJ.

In /Oldenburg et al. 2004/ the economic feasibility of carbon sequestration with enhanced gas recovery has been analyzed for the Rio Vista gas field in California (Figure 7). It is shown there that the gas supply costs are in a range from 3.2 to 5.3 $/GJ depending on the carbon dioxide supply costs and the ratio of the carbon dioxide injected to the incremental methane produced. Here, this range has been applied to the EGR costs for the USA. With the US cost difference between supply costs of EGR and of conventional reserves the EGR supply costs (difference min. 1.8 $/GJ, max. 3.7 $/GJ) for the other world regions have been estimated.

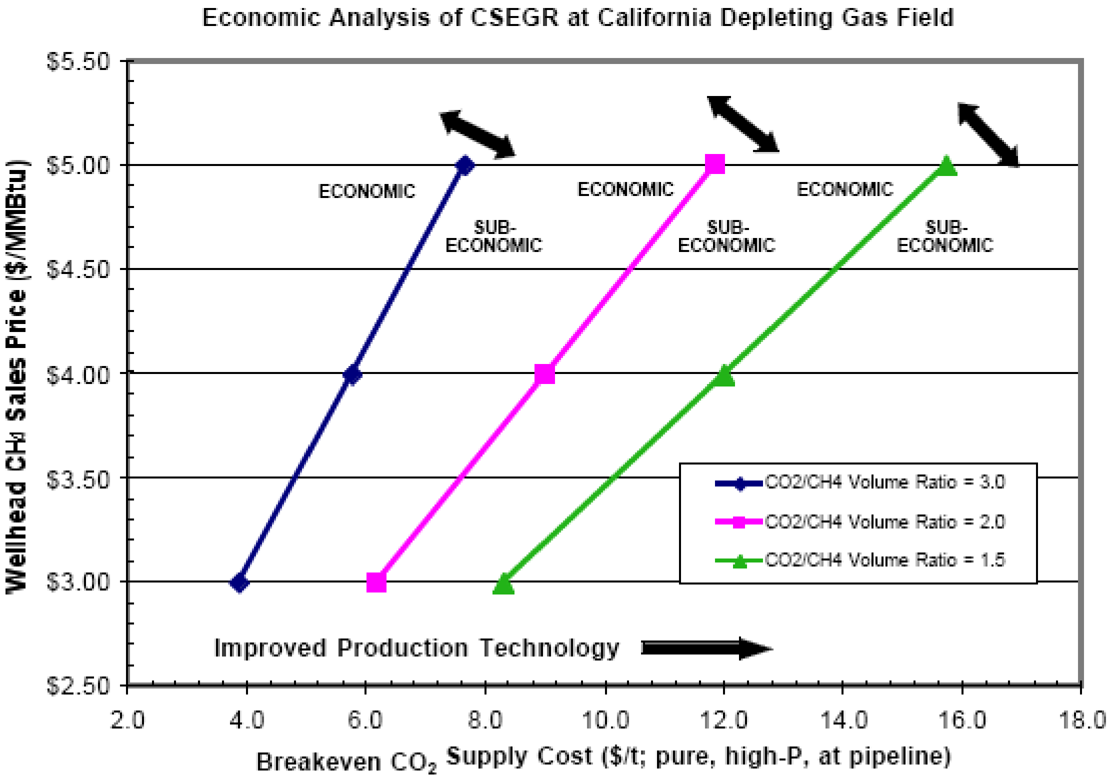

Figure 7: Gas supply costs for a Californian gas field with EGR as a function of CO_2 supply costs and ratio of CO_2 injected to methane produced (/Oldenburg et al. 2004/)

Figure 8 shows based on the reserve and resource amounts in combination with their respective supply costs the global gas supply cost curve. Larger amount of low cost gas quantities particularly exist in the Middle East. The second part of the graph is dominated by the three costs steps of aquifer gas resources with assumed costs ranging from 5.5 to 8 $/GJ.

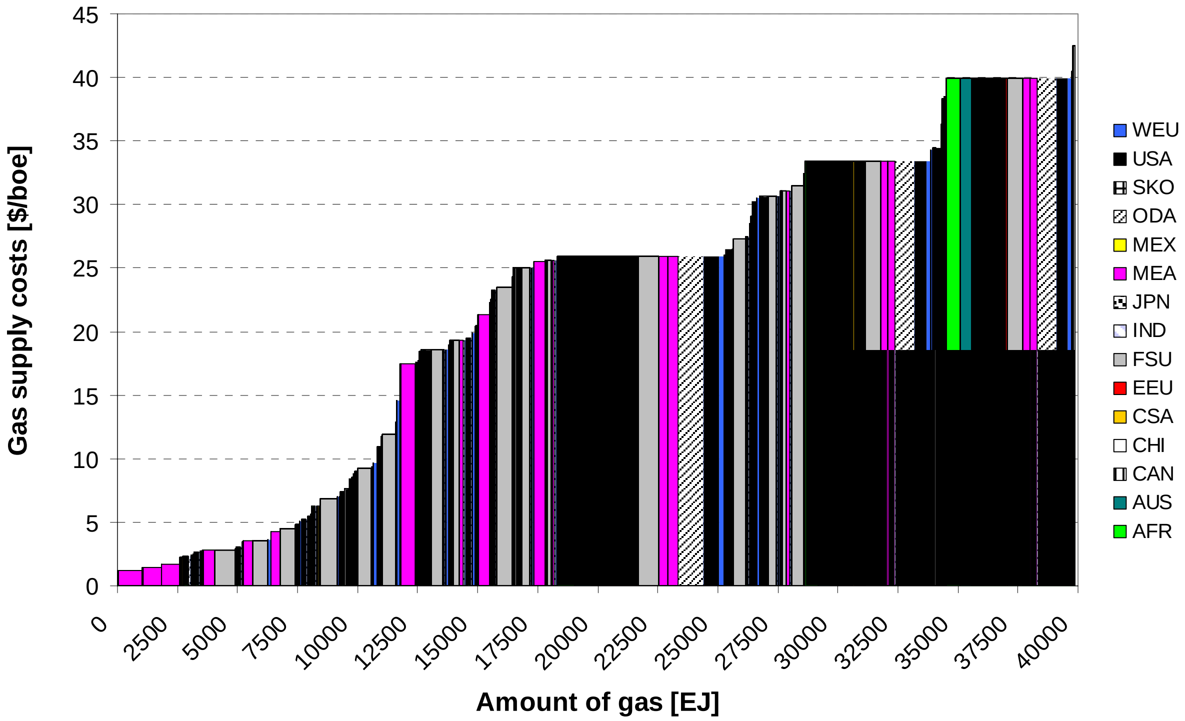

Figure 8: Global gas supply cost curve including conventional and unconventional gas (excluding gas hydrates) for reserves and resources at the beginning of 1998

3.3 Oil

Oil is with a share of 38 % (158 EJ) in global primary energy consumption in 2004 the most important energy carrier in the world (/BP 2005/). After World War II the global oil demand has been growing rapidly (Figure 2). The Arab oil embargo in 1973 and the Iranian Revolution in 1979 initiated a shift to other energy carriers, as natural gas or nuclear, and to efforts for a more efficient use of energy in general. While oil demand is only slowly growing or stagnating in North America, Europe and Eurasia, a large increase in oil demand is observed in Asia over the last years, mainly in to China and India (Figure 9).

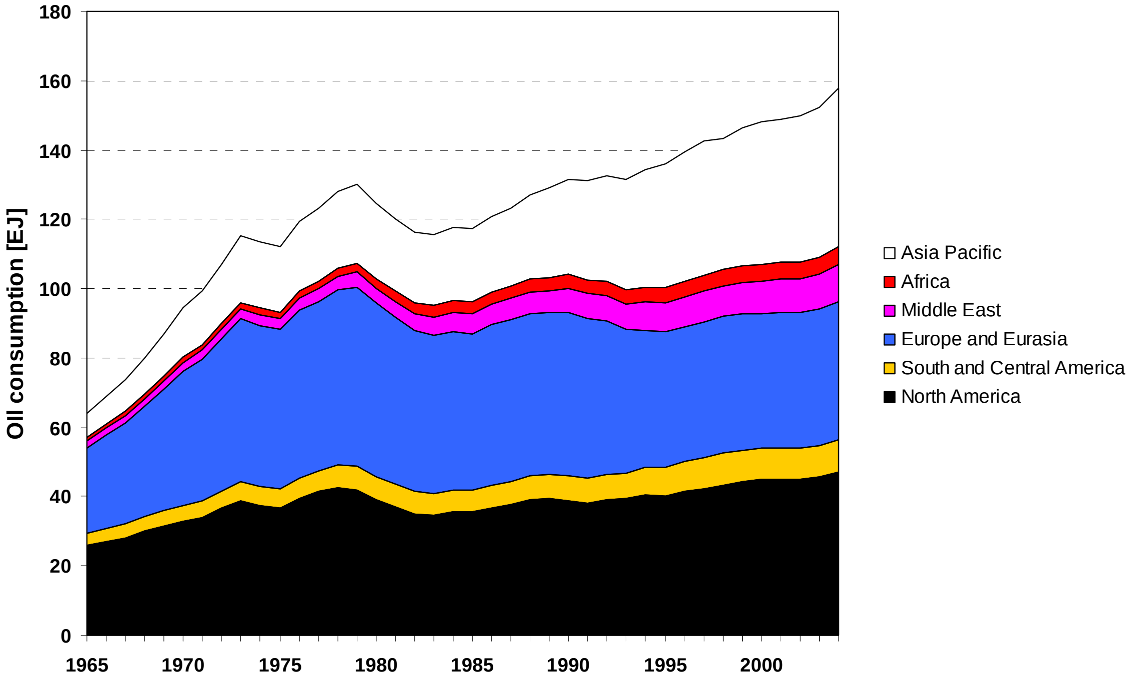

Figure 9: Historic oil consumption by world region (/BP 2005/)

Oil is distinguished according to its density in conventional and unconventional oil. The former one has a maximum density of 0.934 g/cm^3 (or greater than 20°API[4]). Usually, also natural gas liquids (NGL) obtained from gas production are included in the conventional oil resource base. Unconventional categories of oil considered here are oil ands (also called tar sands), extra-heavy oil and oil shales.

The structure of the oil supply module is displayed in Figure 10. Conventional oil resources have been divided in a similar way as for natural gas in the categories recoverable reserves, enhanced oil recovery (EOR) and new discoveries. Unconventional categories are Oil sands, Extra-heavy oil and Oil shales. Each resource category is presented by three costs

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[4] Measure for the density of liquid hydrocarbons. A low API value corresponds to a high density (API = American Petroleum Institute).

steps. Energy input during extraction or for further processing or upgrading is taken into account in production processes following the particular extraction category. Finally, the crude oil obtained from the different resources are mixed into one crude oil commodity, which can either be sent to a refinery or be exported to another model region. As a by-product of conventional oil production natural gas (so-called associated gas) can be obtained.

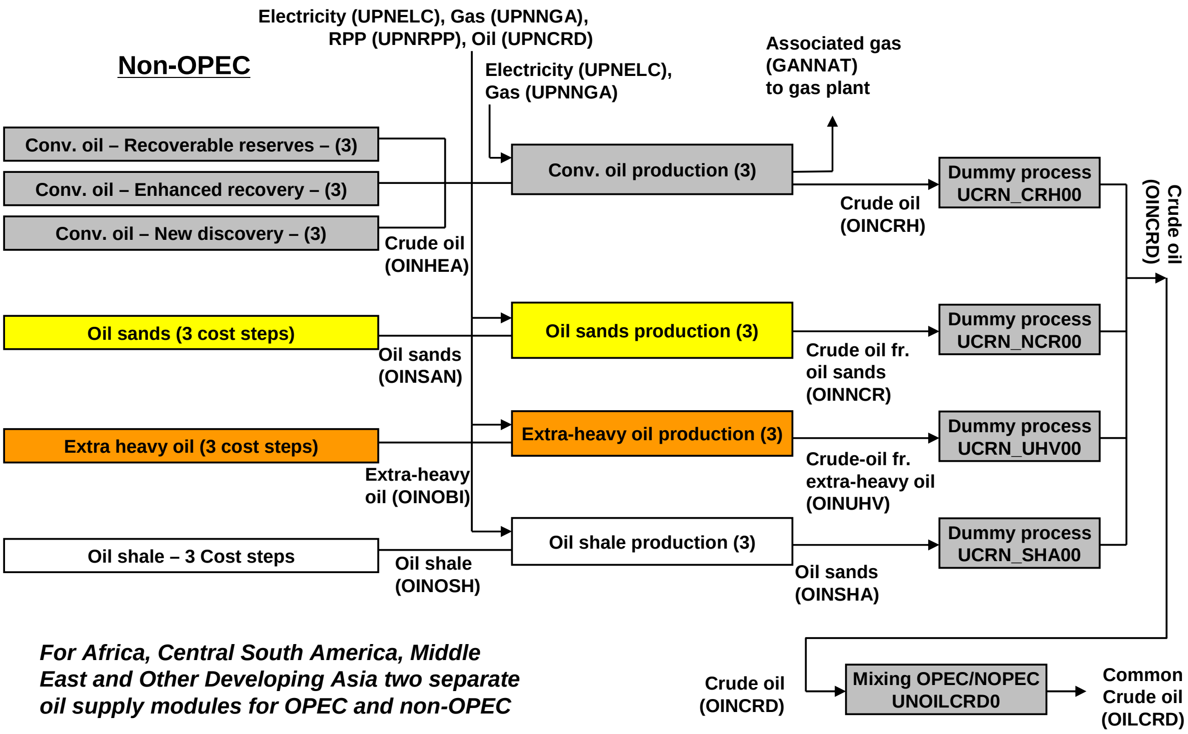
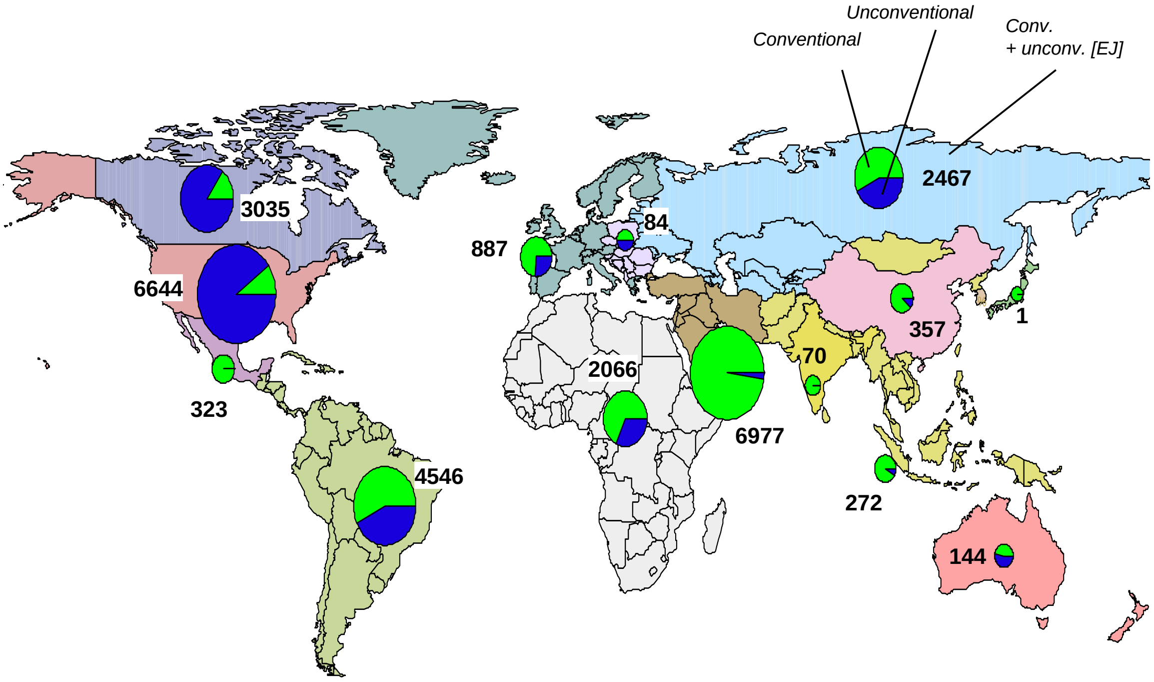


Figure 10: Oil supply module

An overview on the global distribution of conventional and unconventional oil deposits is given in Figure 12. Similar to natural gas conventional oil resources are distributed unequally in the world. While the major part of conventional oil resources is located in the Middle East, the FSU, Africa and South America, large deposits of unconventional oil resources are found in North America. The total remaining resource base for oil added up to 26180 EJ at the end of 2002.



Conventional [EJ]		Unconventional reserves + resources [EJ]			Total [EJ]	Production 2004 [EJ]
Reserves	Resources	Tar sand	Extra heavy oil	Shale oil		
11 776	3 618	3 117	1 616	7 745	27 873	161

Figure 11: Distribution of conventional and unconventional oil deposits at the beginning of 1998 (/WEC 2004/, /USGS 2000/, /BP 2005/)

3.3.1 Conventional oil

161 EJ of conventional oil have been produced in 2004. Ca. 34 % of this production comes from offshore fields. Total conventional reserves and resources added up to 15394 EJ at the end of 1997[5]. Middle East is the region with the highest amount of conventional oil deposits (6880 EJ), followed by Central South America (2749 EJ), the Former Soviet Union (1434 EJ) and Africa (1450 EJ). For conventional oil three categories have been considered here: recoverable reserves, enhanced oil recovery and undiscovered resources. The estimated available oil amounts from these categories are summarized in Table 9. Based on the global oil consumption in 2004, the static lifetime of conventional oil reserves was around 47 years in 2004.

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[5] Based on historic production data reserve and resource amounts have been converted to the end of 1997, since the model horizon of the TIAM model begins with the year 1998.

Table 9: Regional distribution of conventional oil reserves and resources at the beginning of 1998 (/WEC 2004/, /USGS 2000/)

EJ	**AFR**	**AUS**	**CAN**	**CHI**	**CSA**	**EEU**	**FSU**	**IND**	**JPN**	**MEA**	**MEX**	**ODA**	**SKO**	**USA**	**WEU**	**Total**
Recoverable Reserves	655	29	388	172	1632	20	540	39	0	4296	134	108	0	263	192	**8468**
EOR	260	14	129	76	518	14	325	17	1	1388	72	64	0	335	95	**3308**
Undisc. Resources	535	29	16	69	599	9	569	15	0	1197	117	78	0	0	386	**3618**
Total	**1450**	**72**	**533**	**318**	**2749**	**43**	**1434**	**70**	**1**	**6880**	**323**	**250**	**0**	**598**	**673**	**15394**

Recoverable Reserves

Global recoverable reserves of conventional including natural gas liquids (NGL) have been estimated by /WEC 2004/ to be around 8468 EJ at the end of 1997. Saudi-Arabia is with 1511 EJ the country with the largest amount of recoverable conventional oil reserves. Further large occurrences in the Middle East are located in Iran (647 EJ), Iraq (650 EJ), Kuwait (557 EJ) and UAE (545 EJ). Altogether, the Middle East holds 4296 EJ or 51 % of global conventional reserves. Outside the Middle East, Venezuela has the highest conventional reserves (1440 EJ or 17 % of global reserves), which include, however, also extra-heavy oil (less than 8°API).

Enhanced oil recovery (EOR)

The ultimate recovery from producing fields depends on the quality of the oil and the physical properties of the reservoir rocks. A low viscosity oil produced from a high permeable sandstone may yield an ultimate recovery of 75 % of the oil originally in the pore space of the reservoir. The ultimate recovery of heavy oils tends to be much smaller. Usually, the recovery factor from oil fields is lower, since the technological efforts to reach the ultimate recovery are - depending on the oil price - not cost-effective.

In order to enhance the oil recovery, a variety of methods has been developed. The injection of natural gas or water for keeping up the pressure in the reservoir is common practice in the course of field lifetime (sometimes also referred to as secondary recovery methods). Methods going beyond simple waterflood and gasflood are typically designated as enhanced oil recovery (EOR) methods. The three major EOR processes are thermal, miscible and chemical recovery mechanisms. A common thermal EOR process is the injection of steam or hot water from separate wells to decrease the viscosity of the oil in the reservoir and thus to allow for a better flow of the oil to the production well. Another thermal recovery process is the in-situ combustion (fire flooding) of a small portion of the oil in the reservoir to increase the temperature. The process is, however, complicated and its capital costs are high, so that the application of in-situ combustion methods has not gone beyond field trials.

Miscible EOR processes use a solvent that mixes with the residual oil to overcome capillary forces and increase the mobility of the oil. Possible solvents are liquefied petroleum gas (LPG), nitrogen, CO_2, alcohol or methane. To reach a miscible stage certain ranges of reservoir depth and pressure as well as of oil viscosity are necessary for particular solvent. The availability of a sufficient amount of solvent is a further factor influencing the choice and economics of miscible flood projects.

Chemical EOR processes are based on adding polymers, surfactants or alkalis to the water before flooding. Most commonly used is polymer flooding, which raises the viscosity of the injected water, leading to an increase of the recovery factor in the order of 5%. Surfactant flooding, which increases the water solubility of oil, is rarely used due to large capital investment and marginal field improvement. Alkaly flooding is based on a chemical reaction between the alkali and the acids in the oil producing a surfactant which lowers the interfacial tension between oil and water. In 2002, the global production from enhanced oil recovery accounted for 94 Mt or 2 % of the total production /Fries 2005/. /Kosinowski 2002/ estimates that an increase of the ultimate recovery by 1 % for all oilfields of the world would account for one annual global production.

To estimate the potential from enhanced oil recovery methods it has been assumed here that the average recovery for conventional gas fields without EOR is around 40 %, while it can be increased to 50 % by means of EOR. The calculation method is similar to the one presented above for EGR. Thus, the total potential for EOR has been estimated to be around 3308 EJ.

Undiscovered resources

Estimates of mean undiscovered oil resources, of which the existence can be deduced from geological information, on country level are based on the “Geological Survey World Petroleum Assessment 2000” of the U.S. Geological Survey (/USGS 2000/). Total mean undiscovered oil resources are estimated to be around 3618 EJ. The global distribution of the undiscovered resources is similar to the on of the reserves, the Middle East is the region with the largest amount of undiscovered resources (1197 EJ).

Associated gas from oil production

Associated gas is a mixture of different hydro carbons that is released when natural gas is brought to the surface. In the early years of the oil industry associated gas was often vented or flared. Besides wasting a valuable resource, CO_2 emissions from flaring and methane emissions from venting contribute to the greenhouse effect. In 2001, still 85 bcm (or 3406 PJ) of natural gas have been flared /Cedigaz/, which corresponds to 3.3% of global gas consumption in that year. Large amount of gas have been flared with 33 bcm in Africa. Alternatives to flaring or venting the gas are the reinjection of the gas in the oil field to maintain pressure and thus improve the oil recovery or the collection, processing and transportation of the associated gas to national or international markets. Economic considerations are often a hindrance for further transporting the associated gas, e.g. in form of LNG, or further processing it, e.g. by gas-to-liquid plants to synthetic fuels. Also, regulatory problems concerning access to the gas transport infrastructure, as in Russia, can be an obstacle for a reasonable use of gas obtained at the oil production.

Historic values for associated gas and conventional oil production are displayed in Table 10 for some countries, as far as available in the literature. The input ratios of associated gas to oil production have been updated base on these data for the corresponding regions. For the remaining regions the previous data have been kept for the time being.

Table 10: Associated gas and conventional oil production (/BP 2006/, /EIA 2006c/, /Technology Centre 2005/, /Sener 2004/, /Girdis et al. 2000/, /DTI 2006/)

	Production	**Unit**	**1990**	**1994**	**1995**	**1999**	**2000**	**2001**	**2002**	**2003**	**2004**	**2005**
China	Associated gas	PJ		419								
	Oil	PJ		6116								
	Ratio gas to oil	%		6.9								
Mexico	Associated gas	PJ		3527	3579	4001	3835	3675	3538			
	Oil	PJ		6463	6303	6917	7169	7393	7468			
	Ratio gas to oil	%		54.6	56.8	57.8	53.5	49.7	47.4			
Nigeria	Associated gas	PJ	104	168	160	176	192	216	204	204	240	501
	Oil	PJ	3091	3639	3835	4065	4082	4396	4739	4438	4220	4412
	Ratio gas to oil	%	3.4	4.6	4.2	4.3	4.7	4.9	4.3	4.6	5.7	11.4
Russia	Associated gas	PJ					917				423	
	Oil	PJ					13535				19209	
	Ratio gas to oil	%					6.8				2.2	
UK	Associated gas	PJ				1994	2074	2092	2356	2323	2190	2014
	Oil	PJ				5754	5286	4885	4854	4441	3993	3545
	Ratio gas to oil	%				34.7	39.2	42.8	48.5	52.3	54.9	56.8
USA	Associated gas	PJ	3211	3144	2965	3211	3378	3295	2941	2940	2568	2793
	Oil	PJ	17442	16225	16059	14763	14763	14620	14522	14169	13782	12988
	Ratio gas to oil	%	18.4	19.4	18.5	21.8	22.9	22.5	20.3	20.8	18.6	21.5

Reserve amounts of associated gas are included in the reserve figures for recoverable reserves. Explicit statistics differentiating between associated and non-associated gas reserves are not publicly available.

3.3.2 Unconventional oil

Unconventional oil resources can be divided into oil sands, extra-heavy oil and shale oil. Total unconventional oil resources are with 12479 EJ in the same range as the conventional amount of oil (13702 EJ). While conventional oil and gas deposits are located in the Middle East, FSU, Africa and the South America, large unconventional oil resources have been quantified outside of these regions, namely in the USA oil shale and in Canada oil sands (Table 11).

Table 11: Regional distribution of unconventional oil resources at the end of 2002 (WEC 2004)

EJ	**AFR**	**AUS**	**CAN**	**CHI**	**CSA**	**EEU**	**FSU**	**IND**	**JPN**	**MEA**	**MEX**	**ODA**	**SKO**	**USA**	**WEU**	**Total**
Oil sands	245		2466				401					2		1	1	3117
Extra-heavy oil				3	1610										2	1616
Shale oil	370	72	35	36	187	40	632			97		20		6045	210	7746
Total	**616**	**72**	**2501**	**39**	**1798**	**41**	**1033**	**0**	**0**	**97**	**0**	**22**	**0**	**6046**	**214**	**12479**

Oil sands

Oil sands (also referred to as tar sands or natural bitumen) are a mixture of bitumen, water, sands and clay. Depending on the reservoir depth, oil sands are produced by surface mining, underground mining or by an in-situ method. In the case of mining the extracted oil sands are mixed with water and the slurry is transported via pipeline to a separation plant, where the oil is separated from the sand and the water by a solvent. In the in-situ method the viscosity of the bitumen contained in the oil sands is reduced by injecting steam into the deposit. Two in-situ methods exist: the cyclic steam stimulation (CCS) and the steam assisted gravity drainage (SAGD). In the CCS method steam is injected in the deposit kept there for a few weeks to reduce the viscosity of the bitumen, which can then be produced. In the SAGD method two horizontal wells with a vertical distance of 5 to 10 meters are drilled. Steam is injected in the upper well and the bitumen is then collected in the lower well.

The bitumen separated from the oil sand cannot be directly be used as refinery feed stock. It can be either blended with a dilutent, commonly condensate, to diluted bitumen (DilBit) to meet density and viscosity requirements for pipeline transport to a refinery or it can be upgraded before blending through hydrocracking (addition of hydrogen) to a light, sweet synthetic crude oil (SCO). The mass balance for SCO production reveals that for the production of 100,000 barrels of SCO 210,000 tons of initial ore material from the mine are required /Johnson, et al. 2004/.

In both pathways of producing oil from oil sands production, mining or in-situ, substantial amounts of energy, mainly steam generated usually from natural gas, are required. For mining the natural gas demand is around 250 cubic feet per barrel of oil (0.047 PJ_{Gas}/PJ_{Oil}), for in-situ mining the gas requirement is ca. 1000 cubic feet per barrel of oil (0.189 PJ_{Gas}/PJ_{Oil}). Upgrading to synthetic crude oil requires additional 330 - 730 cubic feet per barrel of oil (0.063-0.138 PJ_{Gas}/PJ_{Oil}) /ACR 2004/.

The overwhelming majority of the recoverable oil sand resources are located in with 2466 EJ in Canada (79 %). For more than 35 years oil sands are produced in the Canadian province Alberta. In 2004, 2183 PJ of bitumen have been produced in Canada, of which 35 % are based on in-situ production and 65 % on mining. Nearly all the bitumen from mining has been upgraded to synthetic crude oil, whereas the bitumen from in-situ extraction is for historic reasons mainly diluted and transported to US refineries being capable of handling the bitumen in coking units.

Extra-heavy oil

Extra-heavy oil is in its density similar to oil sands (> 1 g/cm3), whereas the viscosity of extra-heavy oil is much higher, so that the viscosity of the extra-heavy oil has to be reduced by diluting it. The production methods for the extraction of extra-heavy oil are similar to the in-situ methods of oil sands. To avoid the high energy costs for the steam, also “cold methods to extract extra-heavy oil, e.g. by solvents, are being explored.

Extra-heavy oil reserves nearly exclusively exist in Venezuela, 1610 EJ of 1616 EJ of global reserves are found there. Global production was around 1226 EJ in 2002.

Shale oil

Oil shale is a calcareous mudstone known as marlstone containing an organic material, kerogen, which is a primitive precursor of crude oil. Similar to oil sands, either oil shale can be produced through surface or room and pillar mining or the kerogen can be separated in the reservoir from the rock by in-situ methods. Depending on the deposit, the oil yields from 1 ton of oil shale rock vary between 35 to 245 liters of oil /Johnson, et al. 2004/. In the case of surface mining the chain of producing oil from oil shale consists of the steps: ore mining and preparation, pyrolysis of the oil shale to kerogen oil in surface retorts and upgrading of the kerogen oil by coking or hydrocracking to a refinery feedstock product. Various types of surface retorts have been developed for the pyrolysis process. On a commercial scale the so-called “Union B” type of retort was used by Unocal in the USA from 1981 to 1991, it was, however, shut down due to operational problems with the retort. At present, the Alberta Taciuk Processor (ATP) retort, which has been chosen for industry projects in Australia and Estonia, seems a promising technology.

Deeper oil shale resources require underground mining or in-situ methods. In the case of in-situ oil shale production, the pyrolysis takes place in the oil shale deposit, which is heated by steam, hot gases or heaters. Shell has developed the so-called In-situ conversion process (ICP) technology and tests its viability in Colorado. The ICP process involves placing either electric or gas heaters in vertically drilled wells and gradually heating the oil shale interval over a period of several years until kerogen is converted to hydrocarbon-bon gases and kerogen oil which is then produced through conventional recovery means. Due to high capital costs and the long lead times before production, economic risks of the ICP process are high.

Critical issues in the large-scale oil production from oil shale are the energy input, the disposal of the spent shale and the water requirement. The energy requirement for oil shale production by a retort process is estimated by /Johnson, et al. 2004/ to be around 0.194 PJ/PJ_{Oil}. Roughly 1.2 to 1.5 tons of spent shale result from each barrel of oil produced by surface retorting. Moreover, crushing increases the volume of the spent shale by 15–25 percent compared with the raw shale prior to mining so that additional sites for disposal in addition to using the volume of the underground or open-pit mine for disposal are needed /Bartis, et al. 2005/. Furthermore, approximately 1.3 to 3.3 liters of water per GJ of synthetic oil are required.

Global shale oil resources account with 7746 EJ for more than fourth of the global oil resources. The majority of global shale oil resources are located with 6045 EJ (78 %) in the USA (Colorado, Wyoming, Utah). Further significant amounts of oil shale are situated in Australia, Russia, Brazil, Estonia and China. Global production of shale oil was ca. 24 PJ in 2002 /WEC 2004/. Brazil operates two commercial plants with surface retorts with a combined capacity of 8,500 tons of oil shale ore per day. Until recently, more than 80 percent of Estonian oil shale production was burnt for power generation. Electricity imports from Russian nuclear power plants led to a decline. Three commercial retorts with a total capacity of 8000 barrels of oil operate in Estonia. In China, the installed capacity of oil production from oil shale comprised 90,000 tons of oil.

3.3.3 Oil supply costs

Supply cost curves for the different oil conventional and unconventional oil types have been derived in a similar fashion as gas supply costs using a logistic function approach. The data for the minimum and maximum supply costs are based on a literature review (/WEO 2001,

/EIA 2006b/, /Stauffer 1993/, /JANRE 2004/, /Lake 1992/, /NEBC 2004/, /Qiang et al. 2003/, /Skinner and Arnott 2005/, /Drollas 2005/, /Bartis, et al. 2005/). The resulting cost curve for each oil type has been approximated by a stepwise cost curve consisting of three steps. The minimum (first step) and maximum (third step) costs are given in Table 12.

Supply costs for EOR are ranging from 3-8 $/boe[6] for water flooding, 5-20 $/boe for polymer flooding, 10-25 $/boe for a thermal EOR process, 7-30 $/boe for CO_2 injection and 26-50 $/boe for surfactant flooding (/Lake 1992/, /IEA 2004/). Here, it has been assumed that EOR leads to in the average 10 $/boe (1.85 $/GJ) higher supply costs compared to conventional oil production without EOR.

Table 12: Cost range for the different oil categories in $/GJ

$/GJ		AFR	AUS	CAN	CHI	CSA	EEU	FSU	IND	JPN	MEA	MEX	ODA	SKO	USA	WEU
Reserves	Min	0.7	1.0	2.7	1.0	0.6	1.6	1.0	1.6	2.5	0.5	0.6	1.0	2.5	2.6	2.5
	Max	1.6	1.7	4.3	1.7	1.1	2.6	1.7	2.6	3.1	1.8	1.1	1.5	3.1	4.3	3.1
EOR	Min	2.5	2.7	4.5	2.7	2.3	3.4	2.7	3.4	4.2	2.3	2.3	2.7	4.2	4.4	4.2
	Max	3.8	3.7	7.0	3.7	3.0	4.9	3.7	4.9	5.1	4.2	3.0	3.5	5.1	7.0	5.1
Undisc. Resources	Min	1.2	1.4	3.3	1.4	1.0	2.1	1.4	2.1	2.9	1.0	1.0	1.4	2.9	3.1	2.9
	Max	3.6	3.5	6.7	3.5	2.7	4.7	3.5	4.7	4.8	3.9	2.7	3.2	4.8	6.7	4.8
Oil sands	Min	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1
	Max	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4
Extra-heavy oil	Min	2.3	2.3	1.9	2.3	2.3	2.3	2.3	2.3	2.3	2.3	1.2	2.3	2.3	2.2	2.3
	Max	2.7	2.7	3.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	3.6	2.7	2.7	3.8	2.7
Oil shale	Min	5.6	5.6	5.6	3.9	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6
	Max	8.3	8.3	8.3	8.8	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3

Supply costs for oil from oil sands are reported by /NEBC 2004/ to be between 1.6 – 3.5 $/GJ, excluding the costs for natural gas, since natural gas demand is explicitly modeled as energy input in the oil sand extraction process in the TIAM model, this yields supply costs of 2 – 2.5 $/GJ. These costs have been taken as input for the logistic function given minimum and maximum costs steps of 2.1 and 2.4 $/GJ, respectively.

Oil shale supply costs are estimated to be in the range of 6-9 $/GJ for surface and underground mining. Costs the in-situ production are projected to be around 5 $/GJ, of which roughly one half caused by energy needs for heating the reservoir /Bartis, et al. 2005/. The minimum and maximum values of the cost-step function are 5.6 and 8.3 $/GJ, respectively.

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[6] 1 boe or bbl (barrel of oil) equals 159 liters of oil, 1/7 ton of oil or 5.98 GJ.

The resulting global oil supply cost curve is displayed in Figure 12. The supply costs stated there are at the costs at the wellhead. To dampen the switching between resource categories across regions especially in the first periods of the model horizon a fixed cost amount of 0.5 to 1 $/GJ has been added on the oil production processes following the extraction processes (Figure 10). For the unconventional oil sands and oil shales, the energy input required for extraction and upgrading is modeled as energy input (mainly natural gas) in the respective production processes. The total supply costs for oil sands and oil shale increase by the costs for this auxiliary energy consumption. These costs depend on the preceding production chain and are determined endogenously within a model run.

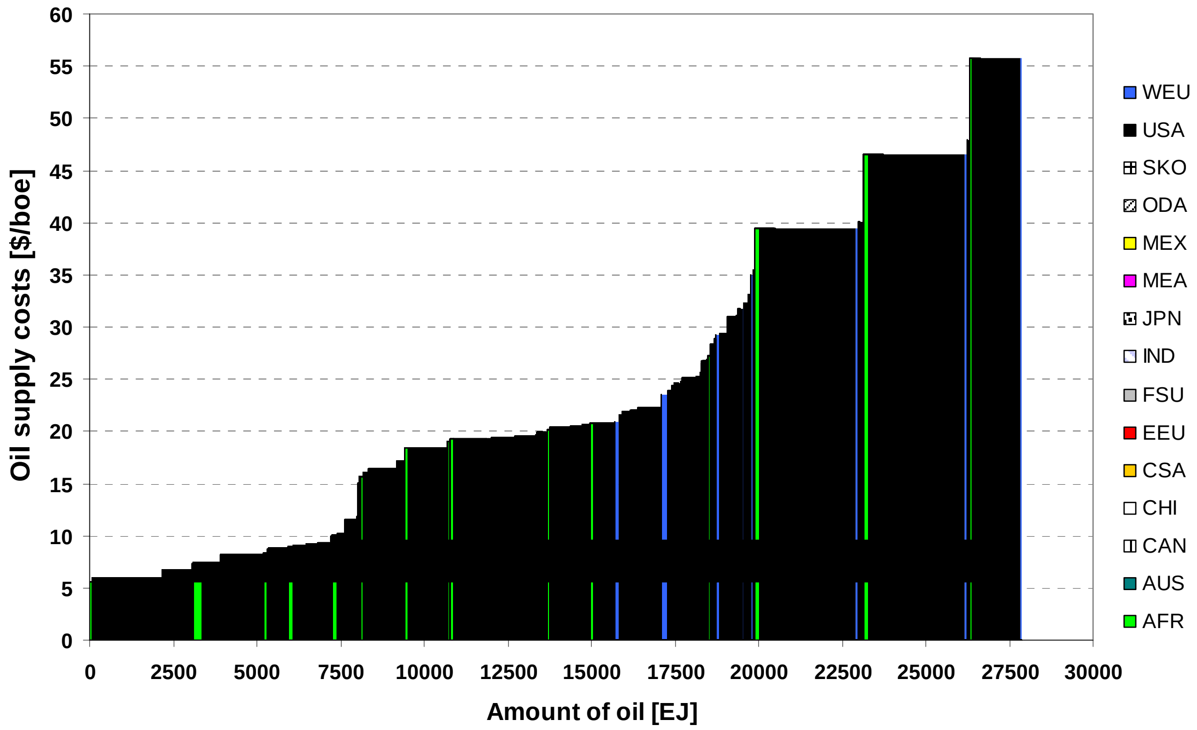

Figure 12: Global oil supply cost curve including conventional and unconventional oil at wellhead for reserves and resources at the beginning of 1998

4 Energy transport

The energy carriers coal, oil and gas are not equally distributed on the world. Especially, conventional resources of oil and gas are concentrated in the Middle East, FSU, South America and Africa. Hence, often large transport distances have to be covered to bring the energy carriers from the producing to the consuming countries.

4.1 Transport options

Depending on the fossil energy carrier different transport systems exist which will be shortly presented for coal, oil and gas in the following.

4.1.1 Coal

Coal is typically transported by rail or ship[7]. Ship transport means either transport by barges on inland waterway or ocean transport across regions by large vessels, such as Panamax (75000 dwt[8]; maximum dimension fitting through the Panama canal) or Capesize (170000 dwt) vessels. Ca. 16 EJ of coal have been traded between the world regions in the year 2005, which corresponds to 13 % of global coal consumption of 121 EJ in that year. Steam coal accounts for 74% of global coal trade, while the remaining trade volume is coking coal. The inter-regional trade flows between the world regions for the sum of hard and coking coal are shown in Table 13 for the year 2005. Major coal exporters are Africa, Australia, China and the USA; major importing regions are Japan, South Korea and Western Europe. In addition, smaller coal volumes are exported by Canada, Venezuela, Columbia, Poland, Indonesia and Vietnam. The gray cells in Table 13 show the inter-regional links that have been depicted as coal trade options.

The statistic coal trade flows for the year 2000 and 2005 have been entered as lower bounds for the coal trade processes in the model.

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[7] Coal can also be transported as a coal-water mixture (slurry) by pipeline. In the USA, a commercial slurry pipeline with a length of 273 miles transports coal from Arizona to a power plant in Nevada. For short distances (up to 100 miles) in some cases also trucks are used.

[8] dwt: dead weight ton

Table 13: Global inter-regional net coal trade (steam coal and coking coal) between world regions for the year 2005 in PJ (/RWE 2005/, /IEA/)

		Destination														
		AFR	**AUS**	**CAN**	**CHI**	**CSA**	**EEU**	**FSU**	**IND**	**JPN**	**MEA**	**MEX**	**ODA**	**SKO**	**USA**	**WEU**
Origin	**AFR**			2						44	42		0	73		1217
	AUS				37	146	0		388	2559	44	51	478	639	4	778
	CAN					95				391	24	27	39	168		148
	CHI			5						539		0		674	0	55
	CSA														82	657
	EEU					4					3					606
	FSU			1			26				155	2		76		287
	IND															
	JPN															
	MEA															
	MEX															
	ODA									433				161	19	254
	SKO															
	USA			520			2		1	101	65	12	3	46		572
	WEU										2					

4.1.2 Oil

Over large distances oil is typically transported via tanker or pipeline[9]. In 2005, the global oil tanker fleet comprised 7863 oil tankers (including product tankers) with a total tonnage of 353.5 Mill. dwt (/ISL 2006/). Oil transport by tanker is quite flexible. Limitations in tanker transport are narrow channels in maritime transport, such as the Strait of Hormuz leading out of the Persian Gulf and the Strait of Malacca linking the Indian Ocean (and oil coming from the Middle East) with the Pacific Ocean (and major consuming markets in Asia) (/EIA 2005/). These channels and also the water depth of harbor terminals may impose restrictions on the size of the tankers.

Larger inter-regional oil pipeline systems exist in the Former Soviet Union/Europe and in North America. The pipeline system in the FSU, nearly entirely owned by the state

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[9] China has imported estimated 72 Mill. boe (431 PJ) of oil by rail from Russia in 2005 (/OGJ 2005/).

company Transneft, transports oil from West Siberia and the Timan-Petschoran region to export harbors at the Baltic coast (capacity 1 Mill. boe/d) and the Black Sea (1.9 Mill. boe/d) as well as via the Druschba pipeline to Eastern and Western Europe (1.3 Mill. boe/d) (/Götz 2005/). In addition, the Baku-Tbilissi-Ceyhan-Pipeline, which runs from Azerbaijan via Georgia to the Turkish Mediterranean harbor of Ceyhan, has started its operation with a capacity of in 2006 with a design capacity of 1 Mill. boe/d in 2009. In July 2006, the 963-km China-Kazakhstan pipeline began its operation. The 0.197 Mill. boe/d pipeline originates at Atasu in west Kazakhstan, enters China at Alashankou port on the Sino-Kazakhstan border, and terminates in the northwestern Xinjiang Uygur Autonomous Region.

On the North American continent, inter-regional oil pipelines (Enbridge, Terasen, Express) with an overall capacity of 1.3 Mill. boe/d also export crude oil and refinery products from Canada to the USA (/NEBC 2005/).

Besides existing pipelines also new pipeline projects running from the FSU to China, South Korea and Other Developing Asia have been considered as future oil transport options (/Park and Lee 2004/).

76 EJ of oil or 48 % of global consumption have been traded between world regions in the year 2004 (Figure 13). Major oil exporters have been the Middle East, the FSU, Africa and South America.

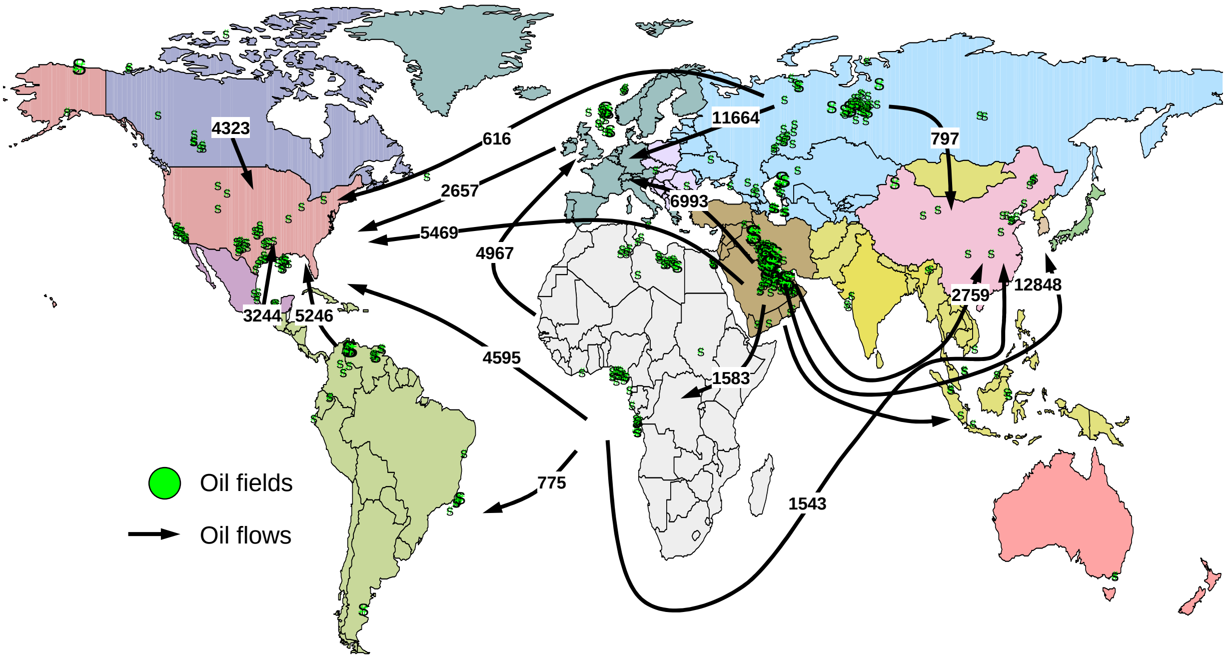

Figure 13: Global oil trade flows in 2004 (/BP 2005/)

Inter-regional trade has been modeled for the commodities crude oil, diesel, gasoline, naphtha and heavy fuel oil (residual fuel oil). By doing this, refineries in the oil producing regions, e.g. Middle East, can be used for to produce petroleum products for exporting. Otherwise, the refineries in these regions would only be utilized in the model to cover domestic petroleum demand.

4.1.3 Gas

Due to its low density transportation costs for natural gas are much higher compared to oil. Hence, trade and markets for natural gas evolved later than for oil. Natural gas can be either transported at high pressure via pipeline or as liquefied natural gas (LNG) by tanker. Global gas trade amounted to 22 EJ or 22 % of global gas consumption in 2004. Thereof 15 EJ have been transported as pipeline gas and the remaining 7 EJ as LNG. Major existing gas pipeline links between world regions are summarized in Table 14.

Table 14: Existing natural gas pipeline export capacities between world regions in 2004

Origin		**Destination**		**Capacity**	**Major Pipelines**
Region	Country	Region	Country	PJ/a	
FSU	Russia	**WEU**	Finland	401	Finland Connector
FSU	Belarus	EEU	Poland	1242	Yamal Pipeline
	Ukraine	EEU	Poland	361	
	Ukraine	EEU	Slovakia	4327	Brotherhood pipeline
	Ukraine	EEU	Hungary	601	
	Ukraine	EEU	Romania	1322	Shebelynka-Izmail Pipeline
FSU		**EEU**	Total	7853	
EEU	Poland	WEU	Germany	1082	Yamal Pipeline
	Czech Republic	WEU	Germany	2244	Transgas Pipeline
	Slovakia	WEU	Austria	2003	Trans Austria Gaspipeline (TAG)
EEU		**WEU**	Total	5329	
WEU	Austria	EEU	Slovenia	160	SOL Pipeline
	Austria	EEU	Hungary	160	Hungary Austria Gaspipeline (HAG)
WEU		**EEU**	Total	320	
AFR	Algeria	WEU	Spain	441	Maghreb-Europe Gas Pipeline (MEG)
	Algeria	WEU	Italy	1162	Transmeditteranean Pipeline (Transmed)
	Libya	WEU	Italy	240	Green Stream Pipeline
AFR		**WEU**	Total	1843	
FSU	Russia	**MEA**	Turkey	641	Blue Stream Pipeline
MEA	Iran	**FSU**	Azerbaijan	881	Baku-Astara Pipeline
EEU	Bulgaria	**MEA**	Turkey	441	Shebelynka-Izmail Pipeline
CAN	Canada	**USA**	USA	6868	
USA	USA	**MEX**	Mexico	1482	

Europe strongly depends in its gas supply from pipeline imports from Russia and North Africa. Russian pipelines run from West Siberia via the Ukraine or Belarus and Eastern Europe and Western Europe. Gas from Algeria is exported via Morocco and Tunisia to Spain and Italy, respectively. A further pipeline connection exists with the Green Stream pipeline Libya and Italy. Cross-border pipelines also exist in North America between Canada and the US and the US and Mexico. The pipeline capacities have been added as residual capacities for the pipeline gas trade processes in the model. It has been assumed that the existing capacity phases out linearly until the end of the model horizon 2100.

The trade flows via pipeline for the year 2005 are given in Table 15. Russian gas exports to Western Europe are shown as transits through Eastern Europe, while for Russian gas exports to Turkey the actually happening transit through Bulgaria and Romania is not reflected in the table, but included in the trade flow between FSU and MEA. Historic gas trade flows for the year 2000 and 2005 have been added as lower bounds on the trade processes in the database.

Table 15: Global inter-regional pipeline net gas trade between world regions for the year 2005 in PJ (/BP 2006/)

		Destination														
		AFR	**AUS**	**CAN**	**CHI**	**CSA**	**EEU**	**FSU**	**IND**	**JPN**	**MEA**	**MEX**	**ODA**	**SKO**	**USA**	**WEU**
Origin	**AFR**	■														1676
	AUS		■													
	CAN			■											3768	
	CHI				■											
	CSA					■										
	EEU						■									3590
	FSU						5245	■			947					
	IND								■							
	JPN									■						
	MEA										■					
	MEX											■				
	ODA												■			
	SKO													■		
	USA											406			■	
	WEU															■

The empty grey cells in Table 15 are possible pipeline links, which currently do not exist, but are added as future options in the model. These are for example the discussed 3000-km Altai-Pipeline from Western Siberia to China, a 2800-km gas pipeline from Iran across Pakistan to India or the Nabucco pipeline project for transporting Iranian or Central Asian gas via Turkey and Eastern Europe to Austria.

To reduce the transport volume natural gas is also transported in liquefied form, which has a 625 times higher density compared to its gaseous state. The transport of LNG requires, however, in addition to special tankers (typically double hull with various insulated internal tanks) liquefaction facilities in the exporting countries and regasification terminals in the importing countries. Especially, the liquefaction terminal and the LNG tankers are capital-intensive, so that, despite the in principal flexible nature of LNG trade, exporters are trying to reduce the demand risk by securing their investment by long term contracts.

The capacities of the existing LNG liquefaction and regasification terminals are given in Table 16. Japan, whose gas consumption entirely relies on LNG, possesses the highest import capacities for LNG. Major LNG exporters in the Pacific basin are Indonesia, Malaysia and Australia, whereas Algeria, Nigeria and Trinidad&Tobago are primarily supplying the US and Europe (Atlantic basin). The LNG suppliers in the Middle East (Qatar, Oman, UAE) are currently due to the higher prices mainly supplying the Pacific market, but because of their favorable, geographic position they might also become a larger supplier for Europe in the future. Comparing the import and export capacities, one notes that the total annual import capacity exceeds the export capacity nearly by the factor 2. For securing supply also during peak demand times some countries, e.g. Japan, have much higher import capacities than their average annual demand.

Table 16: LNG import and export capacities in bcm/a[10] at the end of 2005 (/GLE 2005/, /IJ 2005/, /Simmons 2005/, company websites)

Import		**Export**	
Import countries	**Import capacity**	**Export countries**	**Export capacity**
Belgium	4.5	Algeria	31.9
Dominican Republic	2.75	Australia	22.0
France	15.5	Brunei	9.9
Greece	2.6	Egypt	16.8
India	6.9	Indonesia	40.6
Italy	3.3	Libya	1.2
Japan	259.7	Malaysia	32.6
Portugal	5.5	Nigeria	13.1
Puerto Rico	0.96	Oman	15.2
South Korea	58.5	Qatar	35.2
Spain	33.6	Trinidad&Tobago	20.4
Taiwan	10.28	United Arab Emirates	7.9
Turkey	5.2		
UK	4.4		
USA	42.1	USA	1.9
Total	**455.8**	**Total**	**247.7**

As already the capacity data indicate, Japan was with 3058 PJ in 2005 the largest LNG importer in the world (Table 17). Major LNG producers are Indonesia and Malaysia in the ODA region with 1260 and 1142 PJ, respectively, in 2005. The gray cells in Table 17 denote again the LNG trade links options.

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[10] Assumed conversion factor: 1 bcm = 40.068 PJ.

Table 17: Global inter-regional LNG trade between world regions for the year 2005 in PJ (/BP 2006/)

		Destination														
		AFR	**AUS**	**CAN**	**CHI**	**CSA**	**EEU**	**FSU**	**IND**	**JPN**	**MEA**	**MEX**	**ODA**	**SKO**	**USA**	**WEU**
Origin	**AFR**									3	196			12	202	1412
	AUS								6	523			16	46		3
	CAN															
	CHI															
	CSA														498	26
	EEU															
	FSU															
	IND															
	JPN															
	MEA								236	655			6	574	6	264
	MEX															
	ODA									1803				588	10	6
	SKO															
	USA									73						
	WEU															

The historic LNG trade flows between the world regions for the years 2000 and 2005 have been provided as lower bound for the LNG trade flows. For the following model periods, based on information on long-term LNG contract volumes, as far as public available, further bounds up to the year 2030 have been added (Figure 14, /Simmons 2005/).

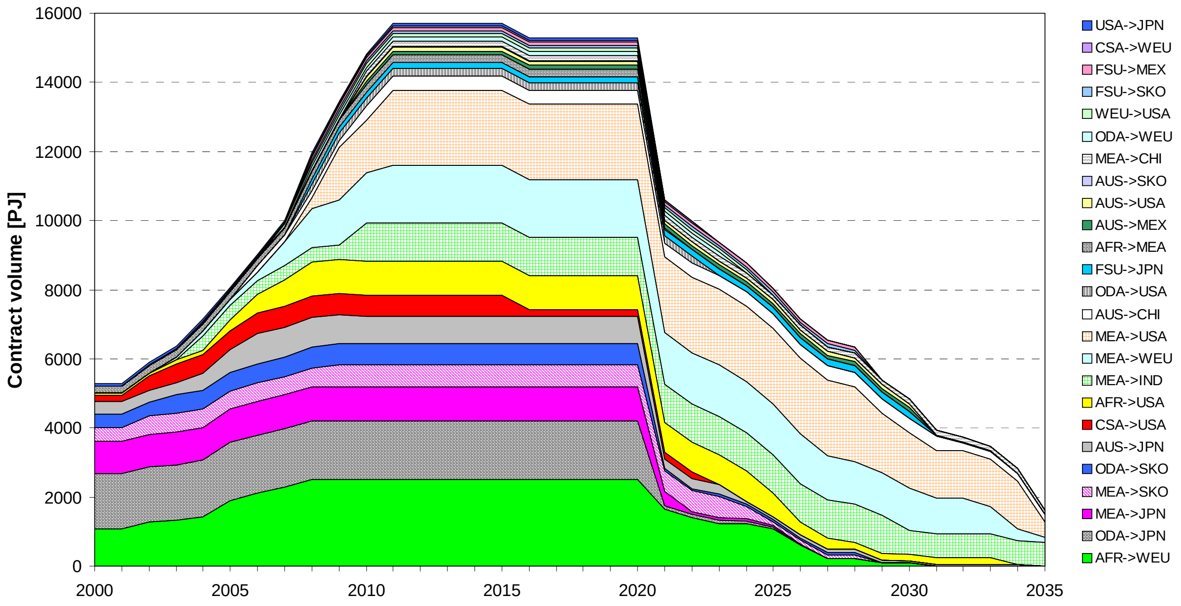

Figure 14: Contracted LNG flows between world regions (/Simmons 2005/)

4.1.4 Transport costs

As presented above different transport options exist for the long distance transport of coal, oil and gas. Coal can be transported by rail or ship, oil and gas can be transported by tanker or pipeline. Besides economic considerations, also other aspects, especially supply security for importers, influence the decision in favor or against a transport option.

The specific transport costs for different energy carriers and transport choices are displayed in Figure 15. The transport costs depend on the distance, but also on the capacity of the transport link, as shown in the case of gas pipelines for different diameters.

Oil and coal transport by tanker have the lowest specific transport costs (0.023 and 0.024 $/GJ/1000km respectively). High transport costs occur for gas pipelines with a low diameter (low capacity) and offshore gas pipelines. It has been assumed here that the costs for offshore pipelines are twice as high as the one for onshore ones. LNG transport includes a fixed cost term due to liquefaction and regasification.

For the oil and gas pipeline transport, cost scale effects due to the capacity (diameter) of the pipeline have not been considered here. Instead for the gas pipeline transport specific, investment costs of 3.7 Mio. $/(PJ/a*1000km) have been assumed (/Zhao 2000/, /PGJ 2004/). For oil, pipeline and tanker transport costs have been given as variable costs. For oil pipeline transport costs of 0.118 $/(GJ*1000km) have been taken (/Soligo and Jaffe 1998/).

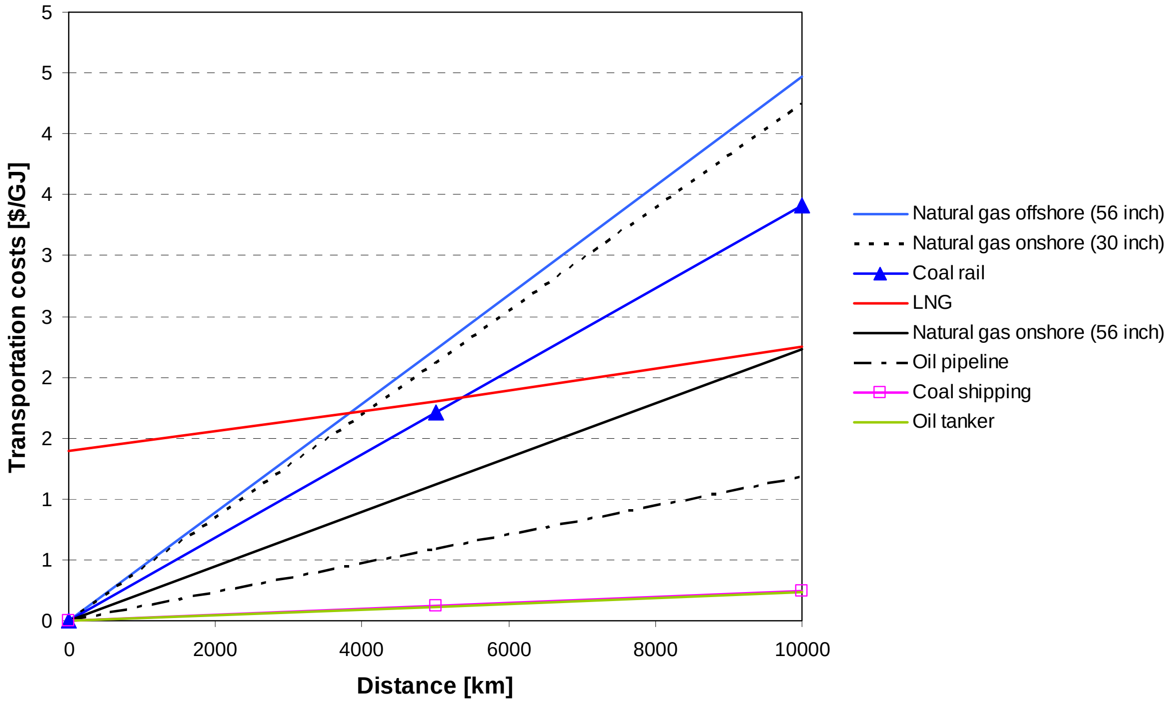

Figure 15: Specific transport costs for coal, oil and gas

The cost assumptions for liquefaction and regasification terminals for LNG are shown in Table 18. Technological progress led to a decline of LNG supply costs, especially for the liquefaction terminal and tanker costs (/Wene 2003/). Economies of scale by building larger LNG trains are an additional factor for cost reductions. The investment costs have been set for the liquefaction process to 4.95 Mill. $/(PJ/a) and for the regasification process to 2 Mill. $/(PJ/a).

Due to this cost decrease several new LNG projects or the expansion of existing facilities are under construction or have been proposed. In the UK, two additional LNG import terminals to the existing one are under construction. New LNG terminals are also discussed in Italy in addition to the existing one. Several countries in Northern Europe (Germany, Sweden, Poland) are considering entering the LNG market in order to diversify their gas supply. The increase in gas prices in the USA over the last years triggered the planning of various import terminals projects. It remains open, how many of these projects will materialize. On the production side, Norway is building Europe’s first LNG liquefaction facility at the Barents Sea being supplied by gas from the offshore Snøvhit field. The gas of Snøvhit is determined for the USA, Spain and France. In Russia, a two train LNG terminal is under construction on the Sakhalin Island at Russia’s Far East coast to supply the Asian market. Gazprom has proposed to build LNG terminals in Murmansk at the Barents Sea and in Ust-Luga near St. Petersburg at the Baltic Sea. With these terminals Gazprom intends to provide the North American market with natural gas. In 2005, Gazprom already sent its first

LNG cargo to the USA based on a swap deal of pipeline gas for LNG with the French company Gaz de France.

Table 18: Cost assumptions for LNG liquefaction and regasification terminal (/Valais et al. 2001/, /Simmons 2005/)

Parameter	Unit	Liquefaction	Regasification
Investment costs	Mio. $/PJ	4.95	2
Fixed operating and maintenance costs	% of Investment/year	3.5	3.5
Availability	h/year	7000	5700
Losses	%	8	2

The costs for transport of oil, LNG and coal by tanker have been calculated for the individual trade routes based on the transport distance, tanker capacity and costs, travel speed and time spent in the harbor. In the following this approach is described for the case of LNG transport. An example calculation for an LNG tanker with a capacity of 135,000 m^3 LNG and with costs of 200 Mio. $ (/Simmons 2005/) covering a distance of 10000 km is shown in Table 19. The formulas to calculate the number of round-trips, the total amount of LNG transported by the tanker in one year and the specific transportation costs (annuity of the investment costs) are:

$$n_{trip} = \frac{24 \cdot \left(365 - t_{ma\,\mathrm{int}}\right)}{2 \cdot d - t_{load} \cdot s} \cdot s$$

$$cap_{tot} = l_f \cdot cap_{tanker} \cdot n_{trip}$$

$$cost_{spec} = \frac{annuity + fom/100 \cdot inv}{cap_{tot}} \cdot$$

The meaning of the symbols is given in Table 18. The distances between the different world regions are shown in Table 20. For each region are representative port has been chosen, e.g. Bonny Island in Nigeria for Africa or Huelva in Spain for Western Europe.

Table 19: Example calculation of specific transport costs for LNG

Parameter	Value	Unit
One way distance (d)	10000	km
Maintenance time per year (t_{maint})	20	days
Speed (s)	23	km/h
Time for loading and unloading per trip (t_{load})	48	h
Number of trips per year (n_{trip})	9	per year
Capacity of the tanker (cap_{tanker})	135000	m^3 LNG
Loading factor (lf)	0.98	
Total transport capacity in one year (cap_{tot})	1193860	m^3 LNG/a
FOM costs tanker (fom)	4	%
Investment costs tanker (inv)	200,000,000	$ per tanker
Lifetime (life)	20	a
Discount rate (dr)	6	%
Annuity (annuity)	17,436,911	$/a
Total annual costs ($cost_{annual}$)	25,436,911	$
Specific annual costs ($cost_{spec}$)	21.31	$/$m^3$ LNG

Table 20: Distances between world regions in Nautic miles[11] for LNG transport (/World Ports/)

		Destination														
		AFR	**AUS**	**CAN**	**CHI**	**CSA**	**EEU**	**FSU**	**IND**	**JPN**	**MEA**	**MEX**	**ODA**	**SKO**	**USA**	**WEU**
Origin	**AFR**	■			10573				6937	10653			8028	10357	3463	400
	AUS		■		2424					2796		7326		2934	7326	
	CAN			■												
	CHI				■											
	CSA					■						2220			2272	
	EEU						■									
	FSU		4653					■		1725				1548	5891	
	IND								■							
	JPN									■						
	MEA								1365	5958	■			6093	11218	4512
	MEX											■				
	ODA				1872					2746			■	2888		
	SKO													■		
	USA														■	
	WEU															■

In a similar way to the LNG transport cost calculation, the tanker transport costs for coal and oil have been calculated between the world regions. Based on tanker capacities and costs in Table 21, a tanker with 100,000 dwt and costs of 39 Mio. $ has been chosen for oil transport and one with 125,000 dwt capacity and costs of 28 Mio. $ for coal transport.

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[11] 1 Nautic mile = 1.852 km.

Table 21: Tanker costs for coal and oil (/IEA 2003/)

Ship type	**Size** 1000 dwt	**Oil tanker** $ million	**Coal tanker** $ million
VLCC	>200	73	
Suezmax	120-200	49	
Capesize	170		39
Aframax	80-120	39	
Panamax	60-80	36	23
Hanymax	51		21
Handysize	30		13

5 Summary

In this undertaking, an overview of the supply situation for the fossil fuels coal, oil and natural gas and the global trade structure for these fuels has been given. A compilation of the cumulative reserve and resource data by world region is given in Table 22. From the fuels considered here, hard coal is the energy carrier with the by far largest quantities of reserves and resources (115541 EJ) with large amounts in China, the FSU and the USA. Conventional amounts of oil and gas account for 17928 EJ and 15394 EJ, respectively, which are mainly located in Africa, Central South America, the FSU and the Middle East. Unconventional oil and gas quantities are in same order of magnitude as the conventional ones. The unconventional hydrocarbons are, however, more evenly distributed among the world regions. It is interesting to note that unconventional oil deposits are mainly found in North and South America. The figures for unconventional gas do not include gas hydrates. Estimations for global recoverable gas hydrate resources are highly speculative. In /BGR 1999/ recoverable resources are estimated around 47407 EJ (1183 tcm). Since technologies to exploit the gas hydrate occurrences do not exist, these estimations have to be taken with cautious.

Table 22: Overview of reserve plus resource data for gas, oil and coal (EJ, end of 1997)

	Gas		**Oil**		**Coal**	
Region	**Conventional**	**Unconventional**	**Conventional**	**Unconventional**	**Hard coal**	**Lignite**
AFR	1,326	2,002	1,450	616	4,232	2
AUS	365	1,861	72	72	5,255	795
CAN	749	1,919	533	2,501	1,283	60
CHI	200	658	318	39	23,798	1,022
CSA	968	3,141	2,749	1,798	1,218	249
EEU	82	248	43	41	1,615	834
FSU	5,552	3,966	1,434	1,033	50,007	2,105
IND	86	56	70	0	2,311	377
JPN	5	3	1	0	3,881	0
MEA	5,527	2,401	6,880	97	154	108
MEX	104	15	323	0	69	3
ODA	759	2,896	250	22	5,367	303
SKO	0	2	0	0	2	0
USA	1,291	2,011	598	6,046	15,999	4,154
WEU	914	783	673	214	352	930
Total	**17,928**	**21,962**	**15,394**	**12,479**	**115,541**	**10,944**

The supply costs for the fossil energy carriers have been calculated based on a logistic function methodology using 3 cost steps for the different oil and gas categories. For hard coal and lignite, the modeling by one costs step for reserves and resources, respectively, has been kept for the time being. The calculation procedure for the costs steps is implemented in the resource Excel files, so that, if necessary in the future, the number of costs steps can be fairly easily increased.

The second part of the project was concerned with the trade of fossil energy carries in form of coal, pipeline gas, LNG and petroleum. For hard coal trade, the sum of steam and coking coal, between the world regions has been considered here. Petroleum trade is distinguished in crude oil and the four petroleum products distillates, gasoline, heavy fuel oil and naphtha. Transport costs for the inter-regional trade have been derived based on the transport distance between the world regions. Coal, oil and LNG transport by ship have been modeled through variable costs, while pipeline gas transport is described by existing capacities and investment costs for new lines. The same applies to the liquefaction and regasification technologies for LNG. The cost assumption and calculations as well as projections for upper and lower bounds on the trade flows for are contained an Excel sheet.

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Appendix A: Resource and trade data excel files

Resource data Excel files

The data for the fossil resources and their supply costs are contained for the fuels coal, gas and oil in the Excel files:

- coal_resources.xls,
- gas_resources.xls and
- oil_resources.xls, respectively.

Each sheet contains as output a scenario import sheet (VEDA_xxx) for importing it into the VEDA-FrontEnd, e.g. copying the sheets for oil, gas and coal in one Excel file for importing them as one scenario into VEDA-FE.

Table 23: Description of the data file coal_resources.xls

Sheet	Purpose
0 – Lignite Production	• Historic lignite production by country used to convert resources at the end of 2004 in resources at the beginning of 1998, the first year of the model horizon
0 – Hard coal Production	• Historic harc coal production by country used to convert resources at the end of 2004 in resources at the beginning of 1998, the first year of the model horizon
1 – Resources	• Coal and lignite reserves and resources on a country level • Aggregation of country data to world regions of the TIAM model (differentiation between OPEC and Non-OPEC)
2 - Categories	• Summary of aggregated reserve resource data on regional level
3 – Production costs	• Supply cost ranges for hard coal and lignite reserves and resources from the literature • Minimum and maximum cost values of each resource category are chosen here for the logistic function approach • Default cost curves (logistic functions) for reserves and resources
4 - Costs	• Calculation of 3 costs steps of the cost curve for each reserve/resource category • Currently only one cost level per category (no 3 cost steps)
5 – Supply Cost Hard coal	• Aggregation and graph for global hard coal supply cost curve assuming 20 costs steps per category (not only 3)
6 – Supply Cost Lignite	• Aggregation and graph for global lignite supply cost curve assuming 20 costs steps per category (not only 3)
VEDA_COAL	• Cumulative resource and supply cost data per resource category • Upper activity bound on production from each category (10 % of cumulative resource category) per year

Table 24: Description of the data file gas_resources.xls

Sheet	Purpose
1 – Conventional	• Conventional gas reserves and resources on a country level • Aggregation of country data to world regions of the TIAM model (differentiation between OPEC and Non-OPEC)
2 – Unconventional	• Unconventional gas reserves and resources on a country level • Aggregation of country data to world regions of the TIAM model (differentiation between OPEC and Non-OPEC)
3 - Categories	• Summary of aggregated conventional and unconventional resource data by world region
4 – Production costs	• Supply cost ranges for conventional and unconventional categories from the literature • Minimum and maximum cost values of each resource category are chosen here for the logistic function approach (Sheets '5 – Cost conv.' and '6 – Cost unconv.') • Default cost curves (logistic functions) for conventional and unconventional gas
5 – Cost conv.	• Calculation of 3 costs steps of the cost curve for the three conventional gas categories (reserves, EGR, resources)
6 – Cost unconv.	• Calculation of 3 costs steps of the cost curve for the four unconventional gas categories (coal-bed methane, aquifer gas, gas hydrates, tight gas)
7 – Supply Cost Gas	• Aggregation and graph for global gas supply cost curve assuming 20 costs steps per category (not only 3)
8 – CBM production	• Historic CBM production in 2001 by region; used as lower bound in the model
VEDA_GAS	• Cumulative resource and supply cost data per resource category • Upper activity bound on production from each category per year (10 % of cumulative resource category for conventional ones and 5 % for unconventional) • Lower bounds for unconventional CBM gas production
SC_DAT	• For deriving world gas supply cost curve • Sorted table of all resource steps for all regions with amount and supply costs
SC_AUX	• For deriving world gas supply cost curve • Auxiliary table for inserting spacing of two rows
SC_CURVE	• For deriving world gas supply cost curve • Final data for world gas supply cost curve • Data from sheet SC_AUX have to copied as values into this sheet
DIAG_SC_CURVE	• World gas supply cost curve

New mining processes have been added in the base year templates for the additional unconventional gas categories coal-bed methane, aquifer gas, tight gas with three cost steps per category.

Table 25: Description of the data file oil_resources.xls

Sheet	Purpose
1 – Conventional	• Conventional oil reserves and resources on a country level • Aggregation of country data to world regions of the TIAM model (differentiation between OPEC and Non-OPEC)
2 – Unconventional	• Unconventional oil reserves and resources on a country level • Aggregation of country data to world regions of the TIAM model (differentiation between OPEC and Non-OPEC)
3 - Categories	• Summary of aggregated conventional and unconventional resource data by world region
4 – Production costs	• Supply cost ranges for conventional and unconventional categories from the literature • Minimum and maximum cost values of each resource category are chosen here for the logistic function approach (Sheets '5 – Cost conv.' and '6 – Cost unconv.') • Default cost curves (logistic functions) for conventional and unconventional oil
5 – Cost conv.	• Calculation of 3 costs steps of the cost curve for the three conventional oil categories (reserves, EOR, resources)
6 – Cost unconv.	• Calculation of 3 costs steps of the cost curve for the four unconventional oil categories (tar sands, extra-heavy oil, shale oil)
7 – Supply Cost Oil	• Aggregation and graph for global oil supply cost curve assuming 20 costs steps per category (not only 3)
8 – Unconv. Production	• Historic production of oil from tar sands, extra-heavy oil and oil shale; used as lower bound in the model
VEDA_OIL	• Cumulative resource and supply cost data per resource category • Upper activity bound on production from each category per year (10 % of cumulative resource category for conventional ones and 5 % for unconventional) • Lower bounds for unconventional oil production
SC_DAT	• For deriving world oil supply cost curve • Sorted table of all resource steps for all regions with amount and supply costs
SC_AUX	• For deriving world oil supply cost curve • Auxiliary table for inserting spacing of two rows
SC_CURVE	• For deriving world oil supply cost curve • Final data for world oil supply cost curve • Data from sheet SC_AUX have to copied as values into this sheet
DIAG_SC_CURVE	• World oil supply cost curve

Trade data Excel files

The data for the global inter-regional trade for the fuels coal, pipeline gas, LNG, crudeoil, distillated, gasoline, heavy fuel oil and naphtha are given in the Excel files:

- trade_coal.xls,
- trade_gas.xls,
- trade_lng.xls,
- trade_oil.xls,
- trade_oildst.xls,
- trade_oilgsl.xls,
- trade_oilhfo.xls and
- trade_oilnap.xls, respectively.

Each sheet contains as output a trade scenario import sheet (VEDA_xxx) for importing it into the VEDA-Front.End, e.g. copying the sheets for all traded commodities in one Excel file for importing as one trade scenario into VEDA-FE. Note, that the trade links have to defined first for the different energy carriers in the trade module in VEDA_FE.

Table 26: Description of the data file trade_coal.xls for hard coal trade

Sheet	Purpose/Contents
CoalTrade	• Overview of trade data applied to the coal trade links in matrix format • Shipping distances • Calculation of shipping costs based on shipping distance (all input data for cost calculation, except distance, are given in the Sheet 'Costs') • Calculation of transport costs (for USA-CAN rail costs, for FSU addition of rail costs to shipping costs to obtain total transport costs) • Trade flows from 2000 and 2005 as lower bounds for trade links (taken from 'Statistics' sheet) • Very small lower bounds on trade in 2050 for interpolation between 2005 and 2050
Statistics	• Steam and coking coal trade flows from IEA statistics for 2000 and 2005 • Aggregation of steam and coking coal flows to coal
Costs	• Input data and example shipping cost calculation • Input data in the yellow cells (except the distance) are used in the cost calculation in the formulas on the sheet 'CoalTrade'
ACT_BND	• Lower bounds from sheet 'CoalTrade' are transformed from the matrix format in an enumeration as a list • Can be used to directly import the data into a TIMES model using the $gdxin facility
ACT_COST	• Transport costs from sheet 'CoalTrade' are transformed from the matrix format in an enumeration as a list • Can be used to directly import the data into a TIMES run using the $gdxin facility
Map	• Sheet needed to directly importing ACT_BND and ACT_COST in a TIMES run
VEDA_COAL	• Data for coal trade (ACT_BND, ACT_COST) in an input format for importing it as a trade scenario into VEDA-FE

Table 27: Description of the data file trade_gas.xls for pipeline gas trade

Sheet	Purpose/Contents
GasTrade	• Overview of trade data applied to the gas trade links in matrix format • Cost data for pipeline links (Investment, variable, FOM costs; calculated on sheet 'Pipelines') • Residual pipeline capacity for 2000, 2005 and 2100 (assumption: linearly phasing-out existing pipeline capacities until 2100) • Technical lifetime for new investments in pipeline capacity (50 years) • Trade flows from 2000 and 2005 as lower bounds for trade links (taken from 'Statistics' sheet) • Very small lower bounds on trade in 2050 for interpolation between 2005 and 2050 • Upper bound on new investments in 2000 and 2005 turned-off by providing very small upper bound • Lower bound on investments in 2010 for pipelines currently under construction (NEGP)
Statistics	• Statistics of pipeline gas flows between world regions in 2000 and 2005
Pipelines	• Existing pipeline capacities between world regions • Cost assumptions for existing and new pipeline links
NCAP_BND	• Bounds on investments from sheet 'GasTrade are transformed from the matrix format in an enumeration as a list • Can be used to directly import the data into a TIMES model using the $gdxin facility
NCAP_TLIFE	• Technical lifetime from sheet 'GasTrade' are transformed from the matrix format in an enumeration as a list • Can be used to directly import the data into a TIMES model using the $gdxin facility
PRC_RESID	• Residual pipeline capacities from sheet 'GasTrade' are transformed from the matrix format in an enumeration as a list • Can be used to directly import the data into a TIMES model using the $gdxin facility
NCAP_COST	• Investment costs from sheet 'GasTrade' are transformed from the matrix format in an enumeration as a list • Can be used to directly import the data into a TIMES run using the $gdxin facility
NCAP_FOM	• FOM costs from sheet 'GasTrade' are transformed from the matrix format in an enumeration as a list • Can be used to directly import the data into a TIMES run using the $gdxin facility
ACT_COST	• Variable pipeline costs from sheet 'GasTrade' are transformed from the matrix format in an enumeration as a list • Can be used to directly import the data into a TIMES run using the $gdxin facility
ACT_BND	• Activity bounds from sheet 'GasTrade' are transformed from the matrix

Sheet	Purpose/Contents
	format in an enumeration as a list - Can be used to directly import the data into a TIMES run using the $gdxin facility
Map	- Sheet needed to directly importing ACT_BND and ACT_COST in a TIMES run
VEDA_GAS	- Data for pipeline gas transport (ACT_COST, ACT_BND, NCAP_FOM, NCAP_COST, NCAP_TLIFE, PRC_RESID, NCAP_BND) in an input format for importing it as a trade scenario into VEDA-FE

Table 28: Description of the data file trade_lng.xls for LNG trade

Sheet	Purpose/Contents
LNGTrade	• Overview of trade data applied to the LNG trade in matrix format • LNG shipping costs calculated in sheet 'TransportCosts' • Trade flows from 2000 and 2005 as lower bounds for trade links (taken from 'Statistics' sheet) • Contractual flows for the years 2010, 2015, 2020, 2025, 2030 as lower bounds for trade links (taken from 'Contracts' sheet) • Very small lower bounds on trade in 2050 for interpolation between 2030 and 2050
Statistics	• Statistics of pipeline LNG flows between world regions in 2000 and 2005
TransportCosts	• Assumed shipping distances between world regions • Calculation of shipping costs based on shipping distance (all input data for cost calculation, except distance, are given in the Sheet 'CostData')
CostData	• Input data and example shipping cost calculation • Input data in the yellow cells (except the distance) are used in the cost calculation in the formulas on the sheet 'TransportCosts'
Contracts	• Contracted LNG trades between world regions as time series
Capacity	• Existing LNG export and import terminals with construction years by world region • LNG export and import terminals under construction by world regions as lower bound • For the years 2000 and 2005 additional upper bound on the construction of new terminals to guarantee that the investment in these periods does not exceed the historic investments
ACT_COST	• LNG shipping costs from sheet 'LNGTrade' are transformed from the matrix format in an enumeration as a list • Can be used to directly import the data into a TIMES run using the $gdxin facility
ACT_BND	• Activity bounds from sheet 'LNGTrade' are transformed from the matrix format in an enumeration as a list • Can be used to directly import the data into a TIMES run using the $gdxin facility
Map	• Sheet needed to directly importing ACT_BND and ACT_COST in a TIMES run
CAP_LNG	• Past investments (NCAP_PASTI) and investment bounds for LNG export and import terminals in a format suitable for importing it as a scenario into VEDA-FE (taken form sheet 'Capacity') • The past years used here have to be added manually in the run file or a separate file being included in the run file
VEDA_GAS	• Data for pipeline gas transport (ACT_COST, ACT_BND) in an input format for importing it as a trade scenario into VEDA-FE

Table 29: Description of the data file trade_oil.xls for crude oil trade

Sheet	Purpose/Contents
OilTrade	• Overview of trade data applied to the crude oil trade in matrix format • Crude oil transport costs calculated in sheet 'TransportCosts' • Trade flows from 2000 and 2005 as lower and upper bounds for trade links (taken from 'Statistics' sheet) • Very small lower bounds on trade in 2050 for interpolation between 2005 and 2050 • Large upper bounds on trade in 2100 for interpolation between 2005 and 2100
Statistics	• Statistics of crude oil trade between world regions in 2000 and 2005
TransportCosts	• Assumed shipping distances between world regions • Calculation of shipping costs based on shipping distance (all input data for cost calculation, except distance, are given in the Sheet 'CostData') • Calculation of transport costs between world regions (addition of pipeline costs for transport to export port in the FSU; pipeline transport for transport from FSU to CHI, SKO and ODA)
CostData	• Input data and example shipping cost calculation • Input data in the yellow cells (except the distance) are used in the cost calculation in the formulas on the sheet 'TransportCosts'
ACT_COST	• Crude oil transport costs from sheet 'OilTrade' are transformed from the matrix format in an enumeration as a list • Can be used to directly import the data into a TIMES run using the $gdxin facility
ACT_BND	• Activity bounds from sheet 'OilTrade' are transformed from the matrix format in an enumeration as a list • Can be used to directly import the data into a TIMES run using the $gdxin facility
Map	• Sheet needed to directly importing ACT_BND and ACT_COST in a TIMES run
VEDA_GAS	• Data for crude oil transport (ACT_COST, ACT_BND) in an input format suitable for importing it as a trade scenario into VEDA-FE

To implement the coal trade in the model, the input commodity of the processes UTRNCKOV00 (coke plant), UTRNGWKS00 (production of town gas), UTRNBLSFU0 (production of blast furnace gas) in the Non-OPEC part and UTRPCKOV00, UTRPGWKS00, UTRPBLSFU0 for the OPEC part had to be changed from CONHCO and COPHCO, respectively, to COAHCO to give the model the option to use in addition to domestic coal also imported coal as input for these processes.

Table 30: Description of the data files trade_oildst.xls, trade_oilgsl.xls, trade_oilhfo.xls, trade_oilnap.xls for trade in the petroleum products distillates, gasoline, heavy fuel oil and naphtha

Sheet	Purpose/Contents
OilTrade	• Overview of trade data applied to the petroleum product trade in matrix format • Petroleum product transport costs calculated in sheet 'TransportCosts' • Trade flows from 2000 and 2005 as lower and upper bounds for trade links (taken from 'Statistics' sheet); empty cells not used • Very small lower bounds on trade in 2050 for interpolation between 2005 and 2050 • Large upper bounds on trade in 2100 for interpolation between 2005 and 2100
Statistics	• Statistics of crude oil trade between world regions in 2000 and 2005 • Emtpy cells, not used
TransportCosts	• Assumed shipping distances between world regions • Calculation of shipping costs based on shipping distance (all input data for cost calculation, except distance, are given in the Sheet 'CostData') • Calculation of transport costs between world regions (addition of pipeline costs for transport to export port in the FSU; pipeline transport for transport from FSU to CHI, SKO and ODA)
CostData	• Input data and example shipping cost calculation • Input data in the yellow cells (except the distance) are used in the cost calculation in the formulas on the sheet 'TransportCosts'
ACT_COST	• Petroleum product transport costs from sheet 'OilTrade' are transformed from the matrix format in an enumeration as a list • Can be used to directly import the data into a TIMES run using the $gdxin facility
ACT_BND	• Activity bounds from sheet 'OilTrade' are transformed from the matrix format in an enumeration as a list • Can be used to directly import the data into a TIMES run using the $gdxin facility
Map	• Sheet needed to directly importing ACT_BND and ACT_COST in a TIMES run
VEDA_GAS	• Data for petroleum product transport (ACT_COST, ACT_BND) in an input format suitable for importing it as a trade scenario into VEDA-FE

Appendix B: Further changes to the TIAM model

During the work with the TIAM model several smaller bugs have been identified and been corrected. As far as possible they have been collected in a separate scenario file called **scen_e_diverses.xls**. The changes are documented in this scenario file by a short explanation.

Some problems required, however, changes in the base year templates, the subres template for new technologies and the file scen_ZysSettings.xls.

Changes in base year templates

The changes in the base year templates are (relative to updated templates sent to IER by Maryse Labriet on May 5, 2006):

- New extraction processes have been added in the base year templates for the additional unconventional gas categories coal-bed methane, aquifer gas, tight gas each with three cost steps.
- To implement the coal trade in the model, the input commodity of the processes UTRNCKOV00 (coke plant), UTRNGWKS00 (production of town gas), UTRNBLSFU0 (production of blast furnace gas) in the Non-OPEC part and UTRPCKOV00, UTRPGWKS00, UTRPBLSFU0 for the OPEC part had to be changed from CONHCO and COPHCO, respectively, to COAHCO to give the model the option to use in addition to domestic coal also imported coal as input for these processes.
- Activation the transfer of petroleum products to refinery feedstock by UTRANSFN00 to eliminate the need for exogenous imports of refinery feedstocks (originally activity bound was set to 1).
- Addition of investment cost data and adjusted existing capacity data for refinery.
- Relaxed user constraint S_ELCCOA2 (Max. share of coal in thermal electricity generation), since decreasing gas reserves at the end of the model horizon induce otherwise also a reducing electricity generation from coal

The calibration procedure caused in some regions excess production of oil and gas in the upstream sector. To not remove the formulas in the cells in the base year templates, the causing fixed activity bounds have been removed in the run file through a GAMS statement . The removed fixed activity bounds are:

- UPRNOH100, UPRNOH200, UPRPOH100, UPRPOH200 in AFR, AUS, CHI, CSA, FSU, ODA, WEU.
- UPRNG100, UPRNG200, UPRPG100, UPRPG200 in all regions.

Changes in subres template for new technologies

The changes in the subres template subres_b-newtechs.xls for new technologies are (relative to updated templates sent to IER by Maryse Labriet on May 5, 2006):

- ECOACCA105: Efficiency has been increased to 46 % and investment costs have been reduced to 1200 $/kW in 2010.
- ECOAAFB105: Investment costs have been reduced to 1075 $/kW in 2003 and 1025$/kW in 2008.
- Decentral PV: Investment costs increased to 10000 $/kW in 2003, 3300 %/kW in 2025 and 2750 $/kW in 2035.
- Central PV: Investment costs increased to 6500 $/kW in 2003, 3750 $/kW in 2020, 2000 $/kW in 2040 and 1750 $/kW in 2050.

Changes in ZysSettings.xls

The following changes in the ZysSettings.xls has become necessary when switching to the VEDA-FE version 2.1.79:

- Using the parameter name “Share+” instead of “Share”
- The interpolation of UC_RHSRT does not work. For the time being, the right-hand side constant is inte-/extrarpolated with the help of additional GAMS code in the run file:

```
UC_RHSRT(R,UC_N,'0',BD)$(SUM(DATAYEAR,UC_RHSRT(R,UC_N,DATAYEAR,BD))) = 1;
UC_T_EACH(R,UC_N,T)$(SUM(BD,UC_RHSRT(R,UC_N,'0',BD))) = YES;
```