Universität Stuttgart
Institut für Energiewirtschaft und Rationelle Energieanwendung
IER

Forschungsbericht

Global resources and energy trade: An overview for coal, natural gas, oil and uranium

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Band 101

Global resources and energy trade:
An overview for coal, natural gas, oil and uranium

The authors want to thank the partners involved in the MENGTECH (Modelling of Energy Technologies Prospective in a General and Partial Equilibrium Framework) project (Research Project N°20121). The work presented was funded by the European Commission under the 6th Framework Programme.

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Juli 2007

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ISSN 0938-1228

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1 Introduction

1.1 Overview

Despite an observed decoupling of economic growth and energy consumption in the industrialized countries in the past, global fossil energy consumption has been continuously increasing in the last decades. Especially, the surge of energy in emerging economies as Brazil, China and India has contributed to the continuation of this trend in recent years. Hereby on a global level, crude oil still represents one of the most important fossil energy carriers. Due to the finiteness of currently utilized conventional hydrocarbon reserves and resources, the question how long conventional oil and gas resources last to cover the demand is of importance. To approximate the future oil production some scientists argue that the production curve follows a bell-shaped so-called Hubbert curve with the area below the Hubbert curve equaling the total quantity of available oil deposits and the peak point representing in an ideal situation the mid-term depletion point, i.e. the year where half of the total oil amount has been consumed. The shape of the curve depends on the total reserve or resource estimate for oil, which is, however, not a static number due to new discoveries or improved technology to increase the recovery from known fields. Therefore, the question whether oil production follows a Hubbert curve is controversially discussed. Independently from this discussion, it cannot be denied that conventional resources do not last forever, so that the question to which degree unconventional oil and gas resources (e.g. tar sands in Canada, extra-heavy oil in Venezuela) as well as alternative secondary fuels as synthetic (e.g. coal-to-liquids) or renewable fuels (e.g. ethanol from sugar cane) can fill the gap between demand and supply in the future.

Against the background of these issues, the purpose of this report is to provide an overview of the current status concerning the global reserves and resources for coal, natural, gas, oil and uranium. Since the usage of a specific resource depends on the one hand on the prevailing market price for the commodity and on the other hand on the production costs for said resource, also an attempt has been made to estimate the supply costs for the different energy resources. While conventional hydrocarbon reserves used today are mainly found in the Middle East and the Former Soviet Union, the transition to the exploitation of unconventional resources, which in the case of oil are located to a large extent in North and South America, will lead to a shift in the global energy trade pattern between world regions. Therefore, also the current global energy trade pattern and capacities as well as an estimation of transport costs for existing and possibly new trade links are being discussed.

Further motivation for this compilation and review of resource information is to provide a basis for resource input necessary in different type of energy models. The underlying methodology of these models may differ in terms of technological and economic detail. So-called bottom-up energy models represent the energy sector in great technological detail, but neglect the remaining sectors of the economy. In contrary, so-called top-down models describe the fundamental economic relationships and drivers of the entire economy, but typically contain only a coarse description of technologies. The type of competition assumed on energy markets, e.g. perfect competition versus an oligopoly, can be a further difference of the modeling approaches. Despite these methodological differences, the models share similar data requirements with respect to resource availability and supply costs for primary energy carriers. The purpose of this report is therefore to provide for global models an overview of the current reserve and resource situation for coal, natural gas, coal and uranium in terms of quantities and costs[1].

1.2 Organization of the report

After a definition of some resource terms and the regional division of the world 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, gas, oil and uranium. In the second part of this report, the energy trade structure between world regions and the assumptions on the transport costs for the different energy carriers are presented. In the appendix, technical information, on how the input data are organized in Excel files, is given.

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[1] The data have been collected on a national basis and have been aggregated to world regions as defined in chapter 2.3. The national data are still available in the database, so that the data may also be used for different regional definitions.

2 Definitions

Before describing the different energy carriers and their occurrences, this section gives a definition of the most commonly terms used in the assessment of energy deposits and specifies the regional aggregation applied in this report.

2.1 Reserves and resources

The quantities of fossil accumulations in the reservoir can be distinguished in *reserves* and *resources*. The terminology and definitions differ depending on the energy carrier (hydrocarbons, coal, uranium) being considered. As an example, the classification system of the Society of Petroleum Engineers (SPE), the World Petroleum Council (WPC) and the American Association of Petroleum Geologists (AAPG) is shown in Figure 2-1 for hydrocarbons (oil and gas). Common is all classifications systems the distinctions by the degree of economic feasibility (vertical axis in Figure 2-1) and the degree of geological certainty regarding the existence of the deposit (horizontal axis). In addition, the energy deposit may be distinguished based on required extraction technology in conventional and unconventional accumulations. In the following the reserve and resource categories for the different energy carriers (oil, gas, coal and uranium) are briefly presented.

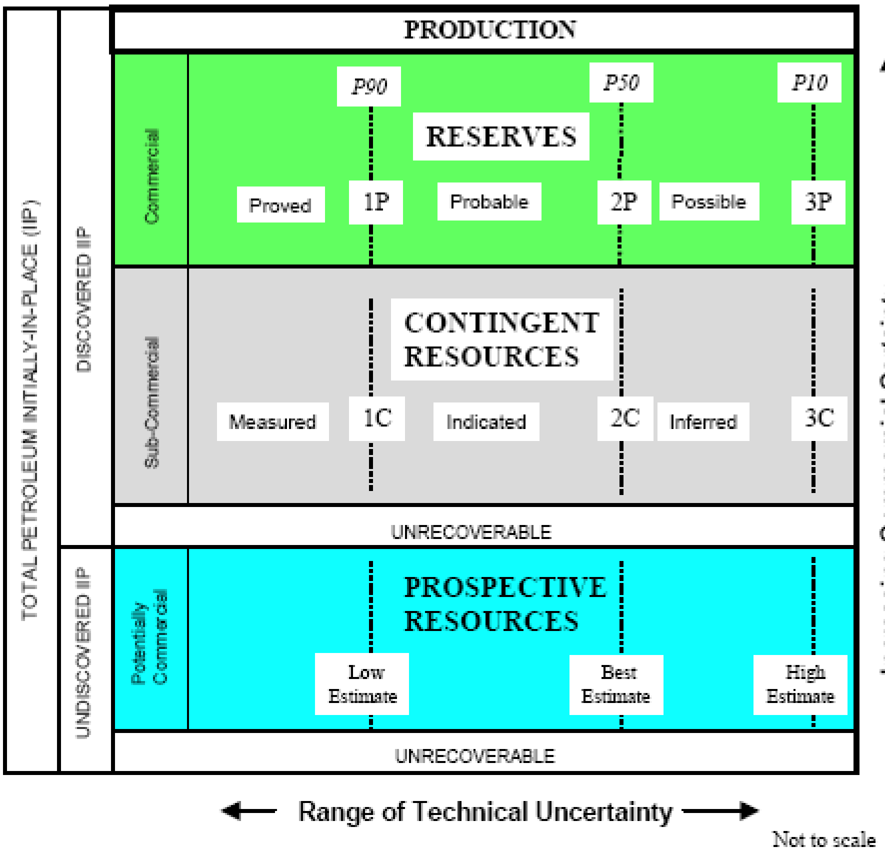

Figure 2-1: Resource classification system for hydrocarbons (/SPE 2006/)

2.1.1 Reserves

Reserves are the estimated quantities at 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 (**Figure 2-1**). Alternatively, one can quote reserve quantities as 90 % likely (P90), 50 % likely (P50) or 10 % likely (P10) to exist.

Uranium reserves are commonly referred to as *Reasonable Assured Resources (RAR)*, if they extraction costs are below 40 $/kg U. This definition goes back to the publication *Uranium 2005: Resources, Production and Demand* (so-called *Red book*, /NEA 2006/) of the Nuclear Energy Agency (NEA). Throughout this report in the assessment of uranium deposits the terminology of the Red Book will be used. Its classification scheme is shown in Figure 2-2.

		Identified Resources		**Undiscovered Resources**	
Recoverable at costs	*< 40 $/kg U*	Reasonably Assured Resources	Inferred Resources	Prognosticated Resources	Speculative Resources
	40-80 $/kg U	Reasonably Assured Resources	Inferred Resources		
	80-130 $/kg U	Reasonably Assured Resources	Inferred Resources	Prognosticated resources	

Figure 2-2: Resource classification system for uranium (/NEA 2006/)

2.1.2 Resources

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. The first group of resources is denoted as *contingent* resources, while the second group is referred to as *undiscovered* resources. Recoverable resources are the part of the resource amount, which can be produced with the present extraction technologies. In the case of oil and gas, only recoverable amounts are considered. For coal, the resource term comprises all in-place, independently whether they are recoverable or not (Figure 2-3). The distinction between reserves and resources is not static. Since the definitions depend on the prevailing economic conditions and available technology options, quantities considered as resources today might be classified as reserves in the future.

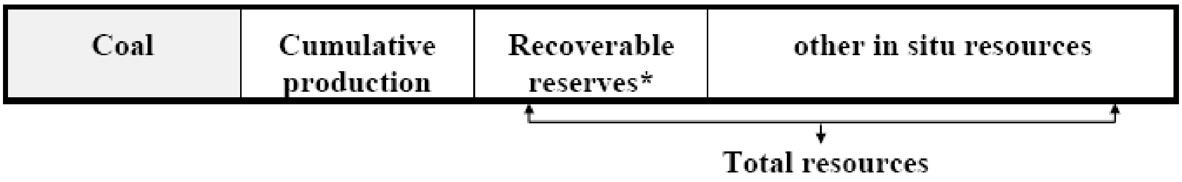

Figure 2-3: Resource classification system for coal (/BGR 2006/)

Uranium resources are distinguished in inferred resources (IR), prognosticated resources and speculative resources (SR). Inferred resources refers to uranium that is inferred to occur due to direct evidence, while prognosticated resources indicate amounts that are expected to exist in well-defined geological areas, but for which the evidence is mainly indirect. Speculative resources are quantities that are thought to exist based on indirect evidence or geological extrapolations. The location of these deposits within a region or geological trend is only roughly known. Reasonable assured resources, inferred resources and prognosticated resources are further distinguished by their extraction costs in three categories (< 40 \$/kg U, 40-80 \$/kg U and 80–130 \$/kg U), whereas speculative resources comprise all quantities being recoverable at costs below 130 \$/kg U.

2.2 Conventional and unconventional energy sources

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 (EOR), 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.

Uranium resources are considered as conventional, if they have an established history of production and are either a primary product or an important by-product of the mining process (e.g. from the mining of copper or gold). Unconventional uranium resources are defined as deposits having only a very low uranium concentration or being only a minor by-product of other mining activities for other commodities. Examples for unconventional resources are uranium in phosphates or in seawater.

2.3 Regions

The global reserve and resource data in this report are presented aggregated to 15 world regions (Figure 2-4), which are: Africa (AFR), Australia&New Zealand (AUS), Canada (CAN), China (CHI), Central&South America (CSA), Eastern Europe (EEU), the Former Soviet Union (FSU), India (IND), Japan (JPN), the Middle East (MEA), Mexico (MEX), other developing Asia (ODA), South Korea (SKO), USA (USA) and Western Europe (WEU).

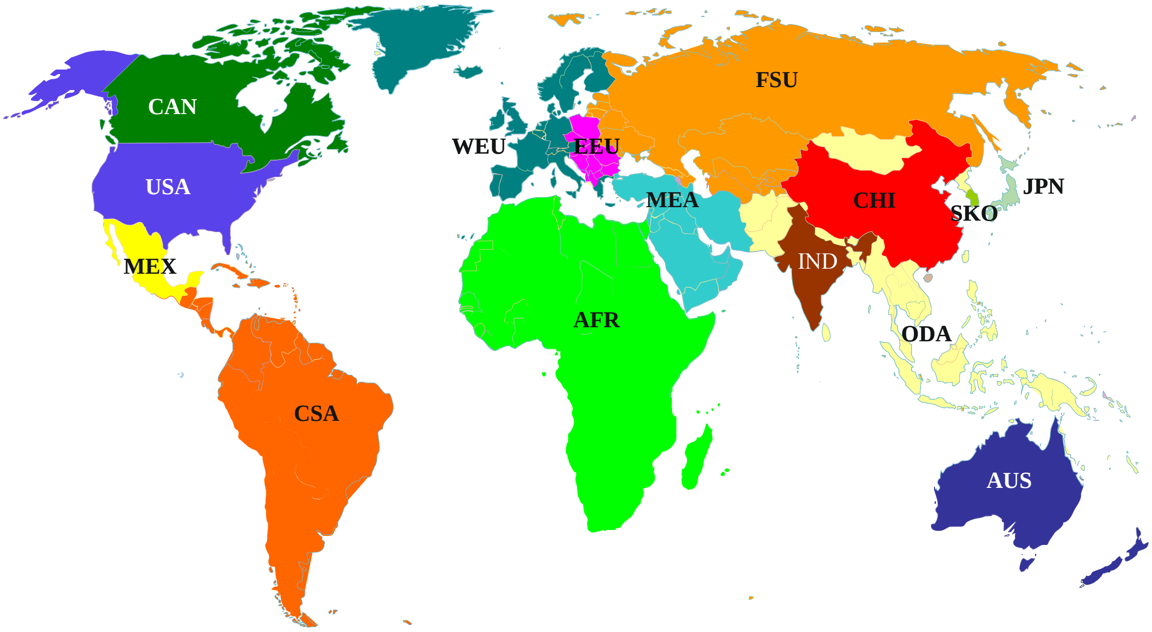

Figure 2-4: Global world regions

The particular countries belonging to the world regions are listed in Table 2-1.

Table 2-1: Definition of world regions

AFR	AUS	CSA	EEU	FSU	MEA	ODA	WEU	Single country regions
Algeria	Australia	Argentina	Albania	Armenia	Bahrain	Bangladesh	Austria	Canada (CAN)
Angola	New Zealand	Bolivia	Bosnia-Herzegovina	Azerbaijan	Cyprus	Brunei	Belgium	China (CHI)
Benin		Brazil	Bulgaria	Belarus	Iran	Taiwan	Denmark	India (IND)
Cameroon		Chile	Croatia	Estonia	Iraq	Indonesia	Finland	Japan (JPN)
Congo		Colombia	Czech Republic	Georgia	Israel	North Korea	France	Mexico (MEX)
Congo Republic		Costa Rica	Hungary	Kazakhstan	Jordan	Malaysia	Germany	South Korea (SKO)
Egypt		Cuba	Macedonia	Kyrgyzstan	Kuwait	Myanmar	Gibraltar	United States (USA)
Ethiopia		Dominican Republic	Poland	Latvia	Lebanon	Nepal	Greece	
Gabon		Ecuador	Romania	Lithuania	Oman	Other Asia	Greenland	
Ghana		El Salvador	Slovakia	Moldova	Palestine	Pakistan	Iceland	
Ivory Coast		Guatemala	Slovenia	Russia	Qatar	Philippines	Ireland	
Kenya		Haiti	Yugoslavia	Tajikistan	Saudia Arabia	Singapore	Italy	
Libya		Honduras		Turkmenistan	Syria	Sri Lanka	Luxembourg	
Morocco		Jamaica		Ukraine	Turkey	Thailand	Malta	
Mozambique		Netherland Antilles		Uzbekistan	UAE	Vietnam	Netherlands	
Nigeria		Nicaragua			Yemen		Norway	
Senegal		Panama					Portugal	
South Africa		Paraguay					Spain	
Sudan		Peru					Sweden	
Tanzania		Trinidad-Tobago					Switzerland	
Tunisia		Uruguay					UK	
Zambia		Venezuela						
Zimbabwe								

2.4 Costs

The cost data in this report are expressed in real US dollars, i.e. excluding inflation, of the year 2000.

3 Global 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 as well as uranium are discussed.

3.1 Coal

Coal consumption accounted for 28 % (121 EJ) of global primary energy consumption of 425 EJ in 2005, the second largest share after oil with 38 % (/BP 2006/). 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[2]. Hard coal is utilized as steam coal for electricity, heat and steam generation and as coking coal in the steel industry (16.5-36 MJ/kg /BGR 2003/). Lignite (soft brown coal) 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 (5.5-16.5 MJ/kg /BGR 2003/), the transport across long distances is not economic.

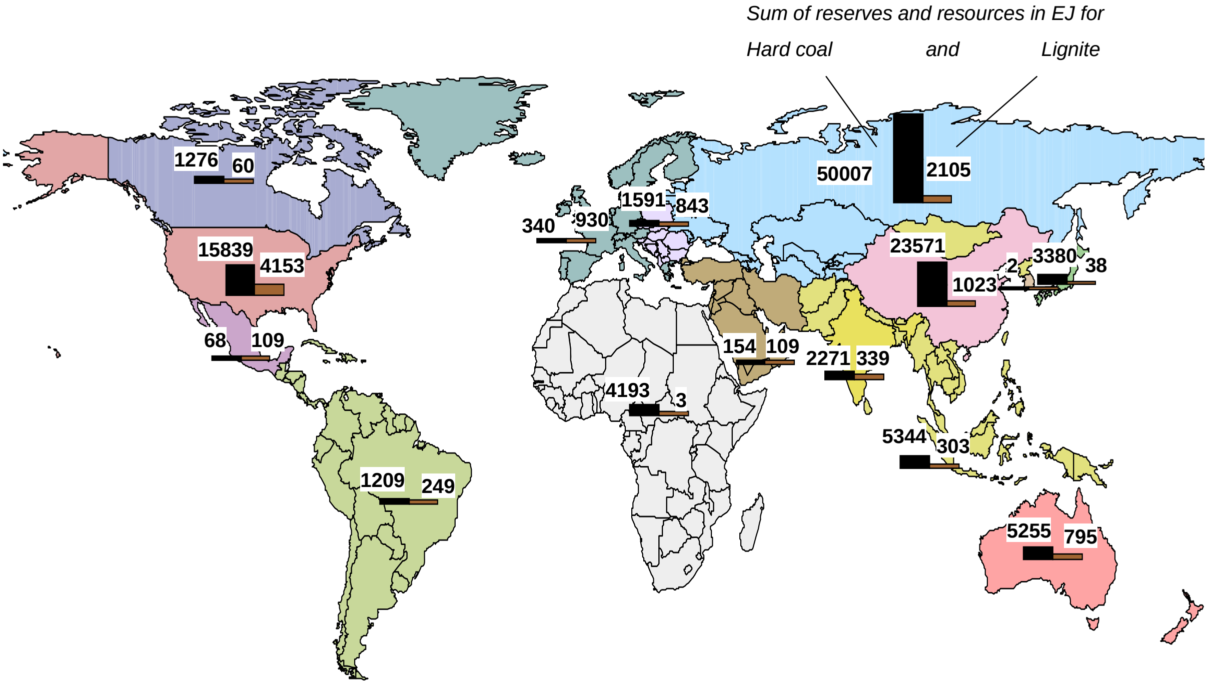

Figure 3-1: Global distribution of coal reserves and resources (/BGR 2003/) at the end of 2004

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[2] Different classification systems (German DIN norm , US ASTM norm, new UN-ECE norm) for coal exist with different coal categories. Here, the DIN classification system as in /BGR 2003/ has been used.

3.1.1 Lignite

Reserves and resources

Global lignite reserves have been 1,977 EJ at the end of 2004, while resources are estimated to be around 8,922 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 (11 EJ) in 2004. The corresponding static lifetime[3] (ratio of reserves to production) for the global lignite reserves corresponds then to 180 years, whereas adding the lignite resources results in a static lifetime of 991 years. The geographic distribution of the lignite reserves and resources on the world regions is given in Table 3-1.

Table 3-1: Global lignite reserves and resources by world region at the end of 2004 (/BGR 2003/, /BGR 2006/)[4]

	AFR	**AUS**	**CAN**	**CHI**	**CSA**	**EEU**	**FSU**	**IND**	**JPN**	**MEA**	**MEX**	**ODA**	**SKO**	**USA**	**WEU**	**Total**
Reserves [EJ]	0	368	30	180	51	277	188	339	0	30	3	85	0	322	104	**1977**
Resources [EJ]	2	427	29	839	198	542	1917	0	38	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**

Lignite 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 3-2). 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), Central and South America (CSA, 0.69 $/GJ), Eastern Europe (EEU, 0.66 $/GJ) and Western Europe (WEU, 0.55 $/GJ). For

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[3] Static lifetime is the ratio of a reserve or resource amount to its production or consumption, respectively. It corresponds to the number of years the resource can be used under the assumption that the production level is constant.

[4] The range of average heating range values deviates slightly from the definition given previously (both taken from /BGR 2003/), probably due to slightly different definition of the boundary between hard coal and lignite in individual countries.

lignite resources, supply costs of 4.7 $/GJ across all regions have been taken from estimates in /Sauner 2000/.

Table 3-2: 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 188,800 EJ (785 Gt) at the end of 2004, while further resources are assessed to be 9,6201 EJ. Large amounts of hard coal can be found in South Africa, Australia, China, the Former Soviet Union, India and the USA (Table 3-3). In 2004, 4,661 Mt of hard coal have been produced on a global level with China (1,956 Mt), the USA (902 Mt), India (369 Mt), Australia (286 Mt), South Africa (243 Mt), Russia (208 Mt) being the largest producing countries. On a global level in 2004, 3.35 Gt have been used for electricity generation, 0.70 Gt for heat and steam generation and 0.55 Gt for steel production /RWE 2005/. Based on this global consumption of 4.6 Gt (110 EJ), the static lifetime of known coal reserves was 171 years in 2004, including additionally the resources, the static lifetime increases to 1046 years.

Table 3-3: Global hard coal reserves and resources by world region at the end of 2004 (/BGR 2003/, /BGR 2006/)[5]

EJ	AFR	AUS	CAN	CHI	CSA	EEU	FSU	IND	JPN	MEA	MEX	ODA	SKO	USA	WEU	Total
Reserves [EJ]	1204	1605	83	2296	362	274	4597	2157	9	35	21	146	2	5975	34	**18800**
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**

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[5] The range of average heating range values deviates slightly from the definition given previously (both taken from /BGR 2003/), probably due to slightly different definitions of the boundary between hard coal and lignite in individual countries.

Hard coal supply costs

The average supply costs for hard coal in the different world regions are summarized in Table 3-4. 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. Exceptions are the rail transport costs for coal exports from the USA to Canada, which have been included in the coal trade costs between the two countries (15 \$/t) as discussed in section 4.1, and the rail transport in the Former Soviet Union from the mine to the harbor, which have also been added to the different transport costs of Russian coal exports (17 \$/t) to other world regions. 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 tariffs in other countries 10 \$/(t*1000 km) as reported in /Schmidt et al. 2005/.

Table 3-4: 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	1.87	1.90	2.71	2.1	1.80	2.37	1.70	2.44	4.51	4.84	2.71	2.03	4.51	2.17	4.51

Low supply costs for known reserves (around 1-1.4 \$/GJ) on a global level are reported in Africa, Australia, South America and the Former Soviet Union. The highest costs (3.7 \$/GJ) occur due to the high labor costs and the typically high depth of the underground coal deposits in Western Europe, South Korea and Japan. Since conventional coal reserves seem to be abundant for the next decades, little attention has been given to the hard coal resources and their extraction costs. For hard coal resources, additional costs of 0.84 \$/GJ have been assumed compared to the costs of the reserves in a particular region. These additional costs for the resource extraction have been derived from /Rogner 1997/.

A global coal supply cost curve for hard coal and lignite combined is shown in Figure 3-2. The curve includes reserves and resources together. 55 % of the total coal deposits (68,000 EJ) can be recovered at costs below 10 \$/boe (1.67 \$/GJ). The majority of these deposits are located in the Former Soviet Union, China and the USA.

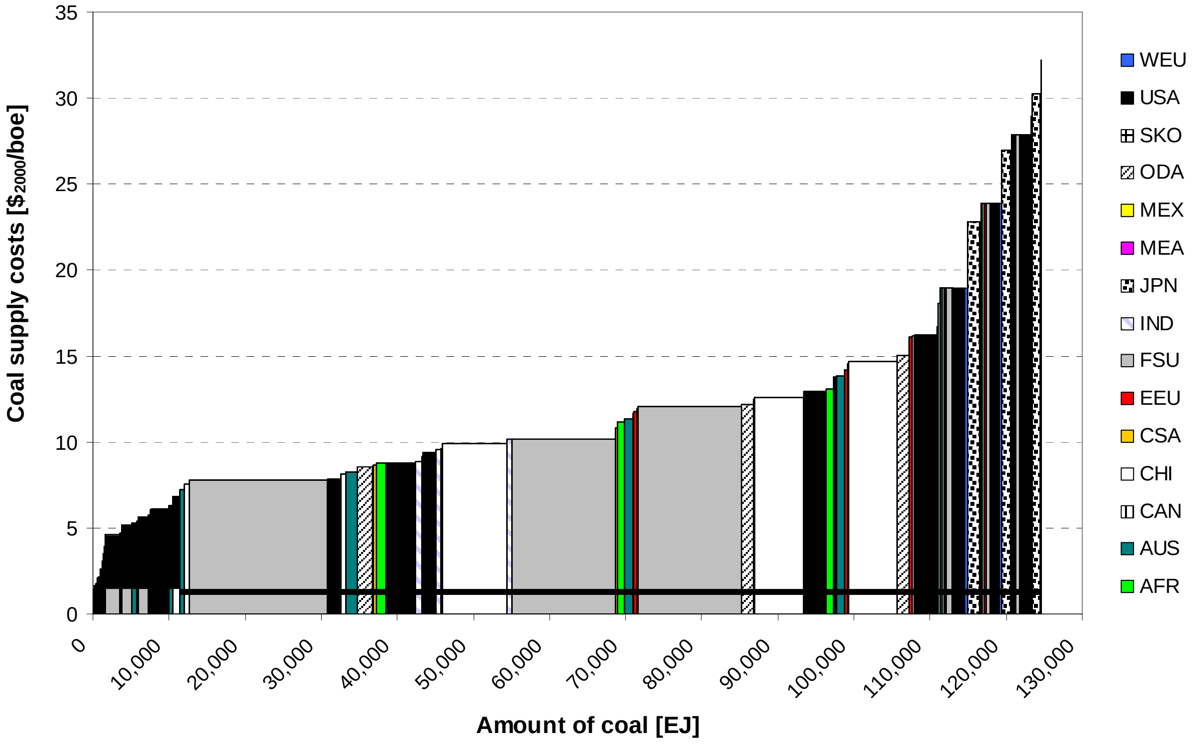


Figure 3-2: Global coal supply cost curve (hard coal and lignite) at the end of 2004

3.2 Natural gas

Natural gas consumption continually increased on a global level. From 27 EJ in 1965 its consumption nearly quadrupled to 104 EJ in 2005 (**Figure 3-3**). 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 in efforts to combat climate change.

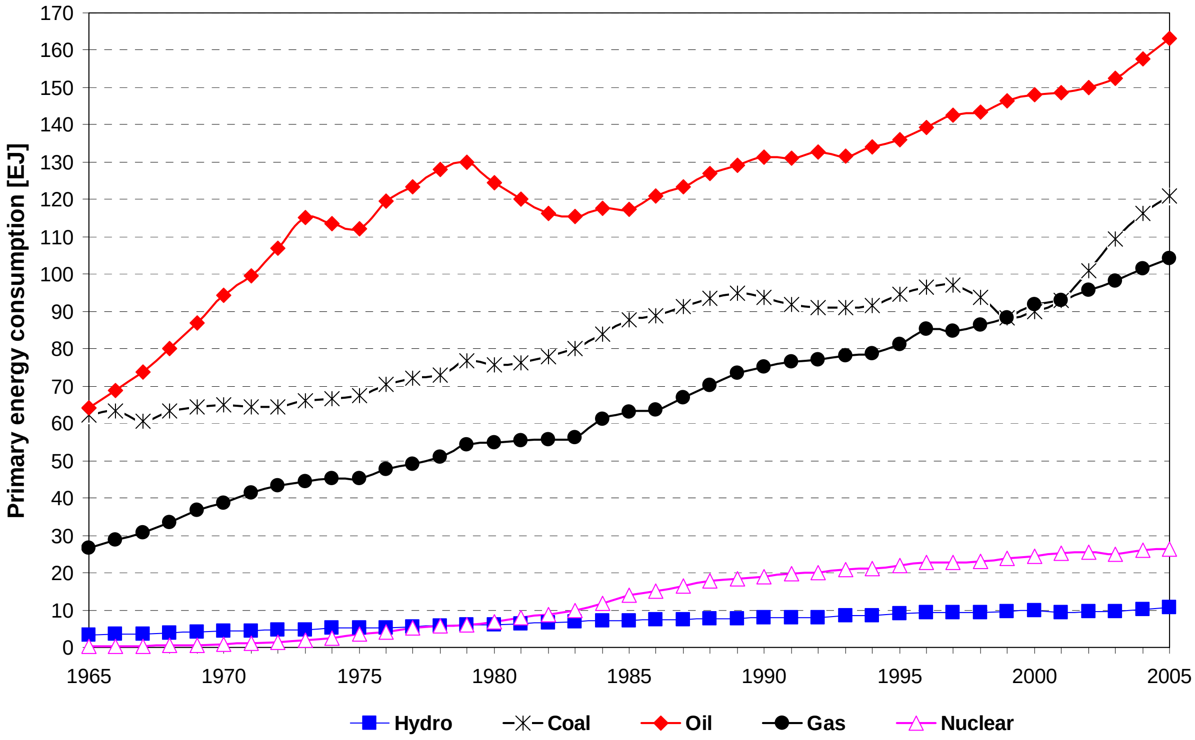


Figure 3-3: Historic development of global primary energy consumption (/BP 2006/)

The different gas supply options considered in this analysis are shown in Figure 3-4. Conventional gas is divided in the categories recoverable reserves, enhanced gas recovery (EGR), resources (contingent and undiscovered). 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 divided in three cost classes.

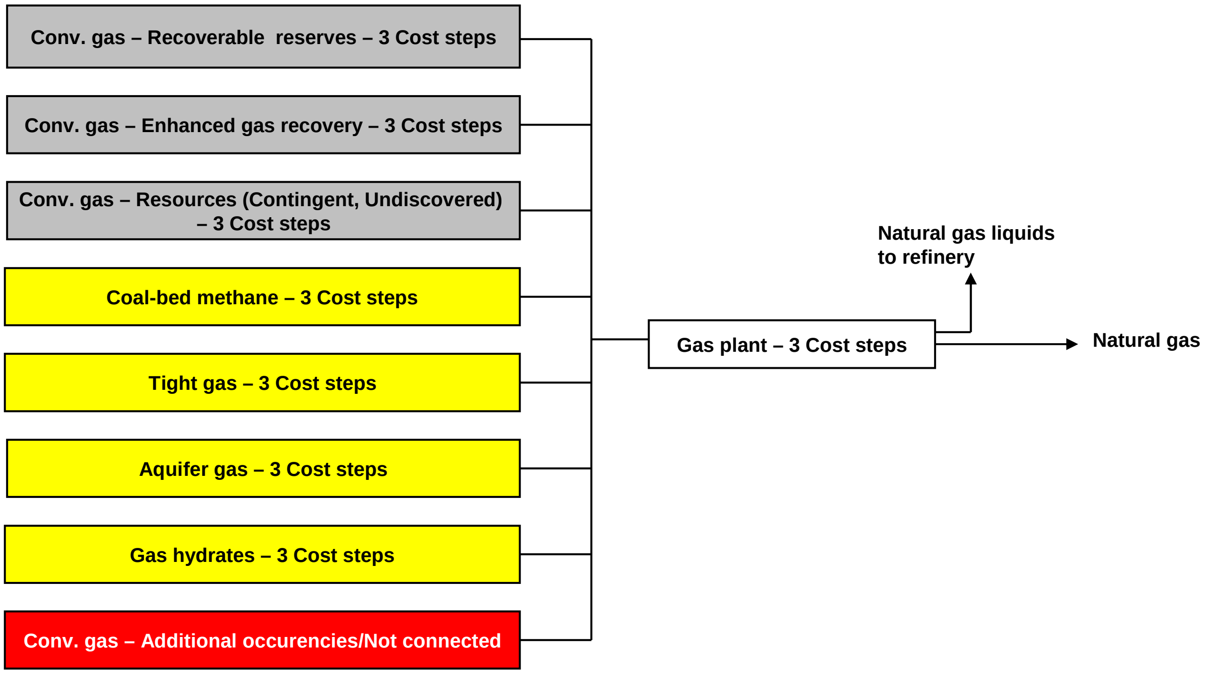
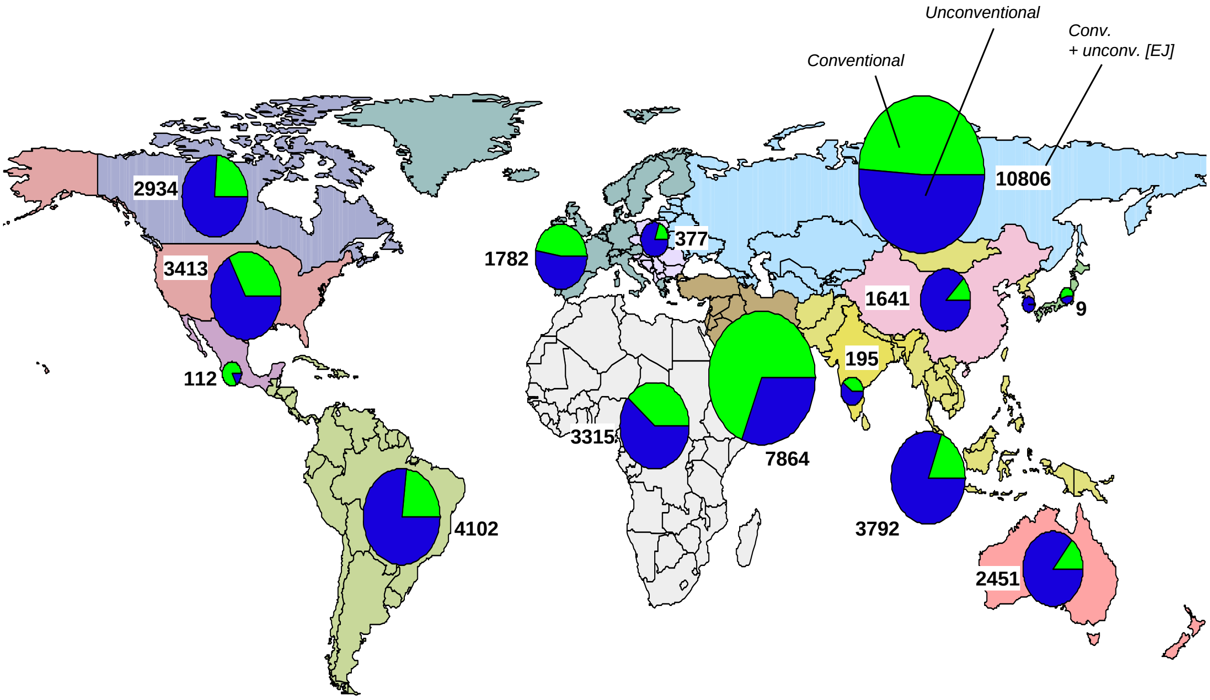


Figure 3-4: Overview of gas supply resources

An overview on the global distribution of conventional and unconventional gas deposits is given in Figure 3-5. 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.

Based on a global natural gas consumption of 104 EJ in 2005, conventional gas quantities would last for 165 years, whereas taking into account in addition the unconventional gas deposits (excluding gas hydrates) the static lifetime would extend to 412 years.



Conventional [EJ]		Unconventional reserves + resources [EJ]			Total [EJ]	Gas hydrates resources [EJ]	Gas production 2005 [EJ]
Reserves	Resources	Coal-bed methane	Tight gas	Aquifer gas			
11918	5256	6490	1694	17441	42799	47400	103

Figure 3-5: Distribution of conventional and unconventional gas deposits at the end of 2005 (/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 17,174 EJ. These amounts are geographically uneven distributed on the world. The largest amounts of conventional gas are located with 5,456 EJ (31 %) in the Middle East and 5,342 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 contingent (i.e. known) and 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 3-5 for the different world regions.

Table 3-5: Regional distribution of conventional gas reserves and resources at the end of 1998 (/WEC 2004/, /USGS 2000/)

EJ	AFR	AUS	CAN	CHI	CSA	EEU	FSU	IND	JPN	MEA	MEX	ODA	SKO	USA	WEU	Total
Reserves	544	141	358	55	252	16	1905	24	2	2526	11	237	0	132	162	**6364**
EGR past production	41	14	85	12	45	37	430	7	2	68	23	57	0	582	153	**1555**
EGR future production	336	87	227	36	160	11	1193	16	1	1535	9	155	0	116	117	**3999**
EGR total	377	101	312	48	205	47	1623	23	3	1603	32	213	0	697	270	**5554**
Resources	365	112	25	87	478	14	1815	31	0	1327	50	256	0	297	399	**5256**
Total	**1286**	**354**	**694**	**190**	**935**	**77**	**5342**	**78**	**5**	**5456**	**93**	**706**	**0**	**1126**	**831**	**17174**

Reserves

The reserve estimates chosen here comprise the categories of proven recoverable reserves and additional reserves recoverable in the “2004 Survey of World Energy Resources” of the World Energy Council (/WEC 2004/). Global reserves of recoverable reserves add up to 6,346 EJ at the end of 2005[6]. The Former Soviet Union represents with reserves of 1,905 EJ the region with the highest gas reserves. The majority of these reserves are located with 1,620 EJ in Russia. The Middle East is with reserves of 2,526 EJ the region with the second highest gas reserves, of which 944 EJ are found in Iran. On a country level, Iran has the second highest gas reserves after Russia. Together both countries account for 40 % of the global proven gas reserves. Based on the natural gas production in 2005 of 103 EJ, the static lifetime of conventional gas reserves was 62 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 CO_2 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,

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[6] /WEC 2004/ states the reserves at the end of 2002. To obtain an estimate for the reserves at the end of 2005, the production in the years 2003-2005of 301 EJ has been subtracted from the 2002 reserves of 6,665 EJ.

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. The recovery rate or factor describes the cumulative amount of oil that can be produced from a field over its lifetime as a fraction of the original oil in-place (OOIP). A recovery rate for conventional gas production without EGR of 50 % has been stipulated, while for EGR it has been assumed that the recovery rate can be increased by 30 % yielding an overall recovery rate of 80 % (/Nakicenovic et al. 2000/). Thus, the OOIP can be derived by dividing the reserves by 50 %. Then, the additional gas amount from EGR can be calculated by applying the additional recovery factor of 30 % to the total amount-in place. The potential production from EGR has been divided into EGR from past production and future production. On a global level, the potential of EGR from future production is 3,999 EJ. Since past production is excluded, it might be considered as a conservative estimate. Applying EGR to the past production, which might be more expensive, since in some cases production at already abandoned fields has to be resumed, yields additional 1,555 EJ. Thus, the total gas potential from EGR amounts to estimated 5,554 EJ.

Resources

Estimates of resources are based here on mean undiscovered gas resources, of which the existence can be deduced from geological information. Conceptually, resources can be split in contingent resources, i.e. known resources and undiscovered resources. Numbers for these two resource categories are unfortunately not available for all countries. Therefore, the mean resource values of the “Geological Survey World Petroleum Assessment 2000” of the U.S. Geological Survey (/USGS 2000/) have been taken as an approximation of the total amount of conventional resources (sum of contingent and undiscovered resources)[7]. Based on this information, the total gas resources on a global level are estimated to be around 5,256 EJ. Resource values with a probability of existence >95 % are on a world level 2,705 EJ, whereas resources having a probability of existence of at least 5 % comprise 8,915 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

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[7] The USGS assessment only states amounts for P95, P50 and P5 on a global level, i.e. 95 %, 50 % or 5 % chance that at least the stated amount exist. If these fractiles were available on a country level, the P95 value could be taken for the contingent resources and the P50 minus the P95 value for the undiscovered resources.

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)[8] 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 dry natural gas production by world region for the years 2000 and 2005 are given in Table 3-6. 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 (based on a review of new projects listed in the worldwide construction reports of the Oil & Gas Journal /OGJ/).

Table 3-6: 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**

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

In reserve reports, the NGL amounts are typically 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 reported separately in /WEC 2004/.

3.2.2 Unconventional natural gas

The 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 conventional gas is available, in contrast to the situation for oil, reducing the incentive for efforts to explore unconventional gas deposits. Total unconventional gas resources correspond to 73,032 EJ including gas hydrates (Table 3-7).

Table 3-7: Regional distribution of unconventional gas resources at the end of 2004 (/BGR 2003/, /BGR 2006/)

EJ	AFR	AUS	CAN	CHI	CSA	EEU	FSU	IND	JPN	MEA	MEX	ODA	SKO	USA	WEU	Total
Coal-bed methane	51	420	566	1405	46	93	2649	110	4	5	6	354	5	485	294	**6490**
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	**2501**	**4446**	**6928**	**1451**	**8803**	**300**	**32581**	**118**	**5**	**2874**	**19**	**3566**	**5**	**6974**	**2466**	73032

Coal-bed methane

The gas found in many coal seams is rich in methane and often contains high proportions of carbon dioxide and nitrogen. Coal therefore is the source rock of the so-called coal-bed methane gas (CBM)[9]. Coal-bed methane is produced by drilling a well in the coal seam, by high pressure artificial fractures are created in the coal seam, which is then filled with a sand-water mixture. By reducing the pressure afterwards, coal-bed methane can be produced. The depth of the coal seam should not be deeper than 2000 meters, since at higher depths due to the rising 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

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[9] 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/).

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 capture 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/.

Global CBM resources amount to 6,490 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 rock formation with its permeability of less than 0.1 milliDarcy (mD). In contrast to conventional gas reservoirs, where the gas is held in a structural trap, tight gas reservoirs are areally extensive /Kuuskraa 2004/. Tight gas is already being produced in some countries of the world (USA, Canada, Europe, and China). Hydrofracturing of the rock 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 derived, which is then assumed to be valid for all world regions leading to global tight gas resources of 1,694 EJ.

Aquifer gas

Aquifer gases are 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 17,441 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 of global hydrate amounts in-place contain a high level of uncertainty and resources differ considerably ranging from 500 to 1,224,000 EJ for permafrost areas and from 112,000 to 273,600,000 EJ for oceanic sediments /Collett 2002/. Estimates from /BGR 1999/ of 47,407 EJ of recoverable gas hydrates existing on- and offshore combined have been chosen as orientation for the global potential in Figure 3-5.

Natural gas supply costs

Cost curves 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/, /Greene et al. 2003/). 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 3-6 and Figure 3-7.

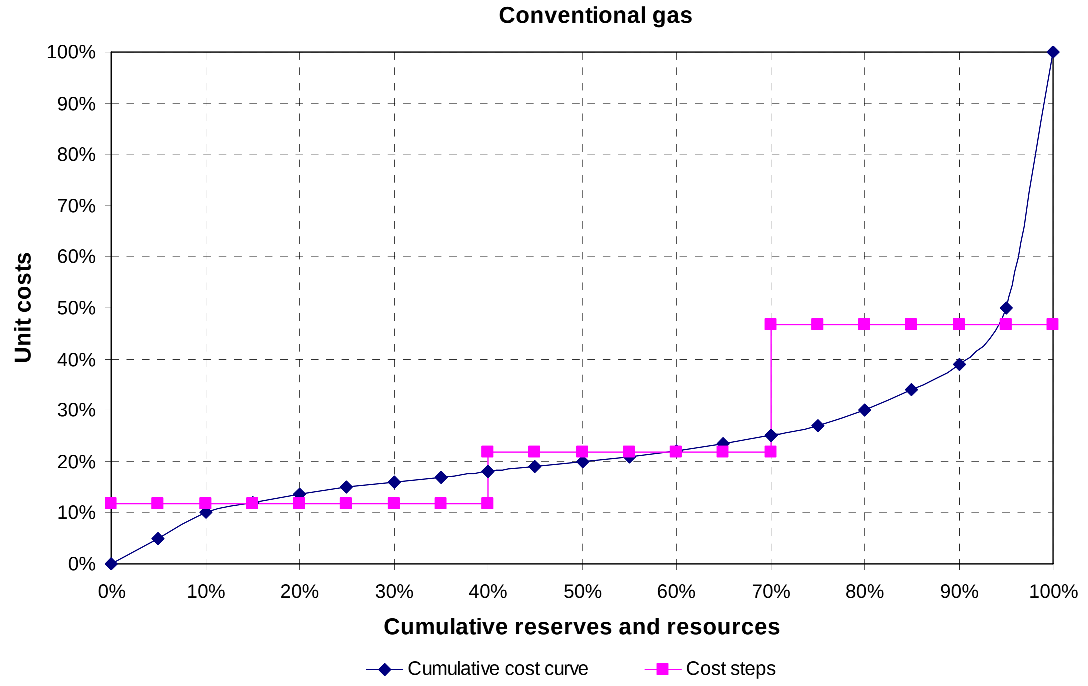

Figure 3-6: Cumulative cost curve for conventional gas resources (adapted from /Rogner 1990/, /Rogner 1997/, /Sauner 2000/)

For each of the different resource categories minimum and maximum supply costs have been estimated from literature sources (/BGR 2003/, /Fainstein et al. 2002/, /OME 2001/, /Oostvorn 2003/, /Rogner 1997/, /Sauner 2000/).

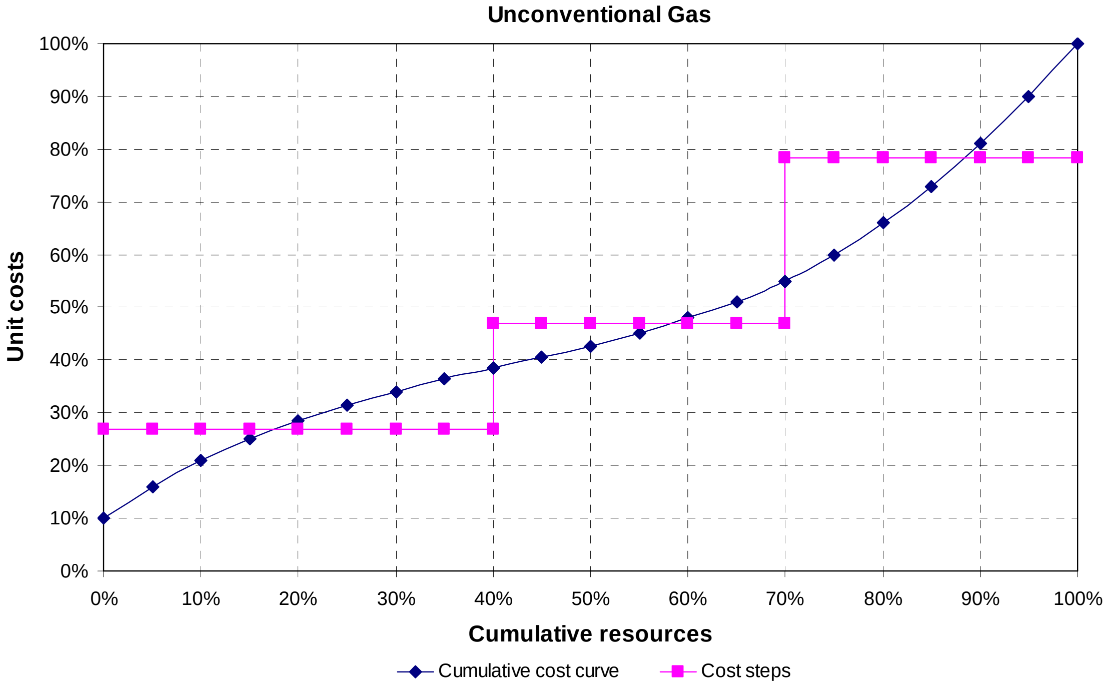

Figure 3-7: Cumulative cost curve for unconventional gas resources (adapted from /Rogner 1990/, /Rogner 1997/, /Sauner 2000/)

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 3-8, where the minimum value corresponds to the costs of the first step and the maximum value to the costs of the third step.

Table 3-8: 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
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 3-8). 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.

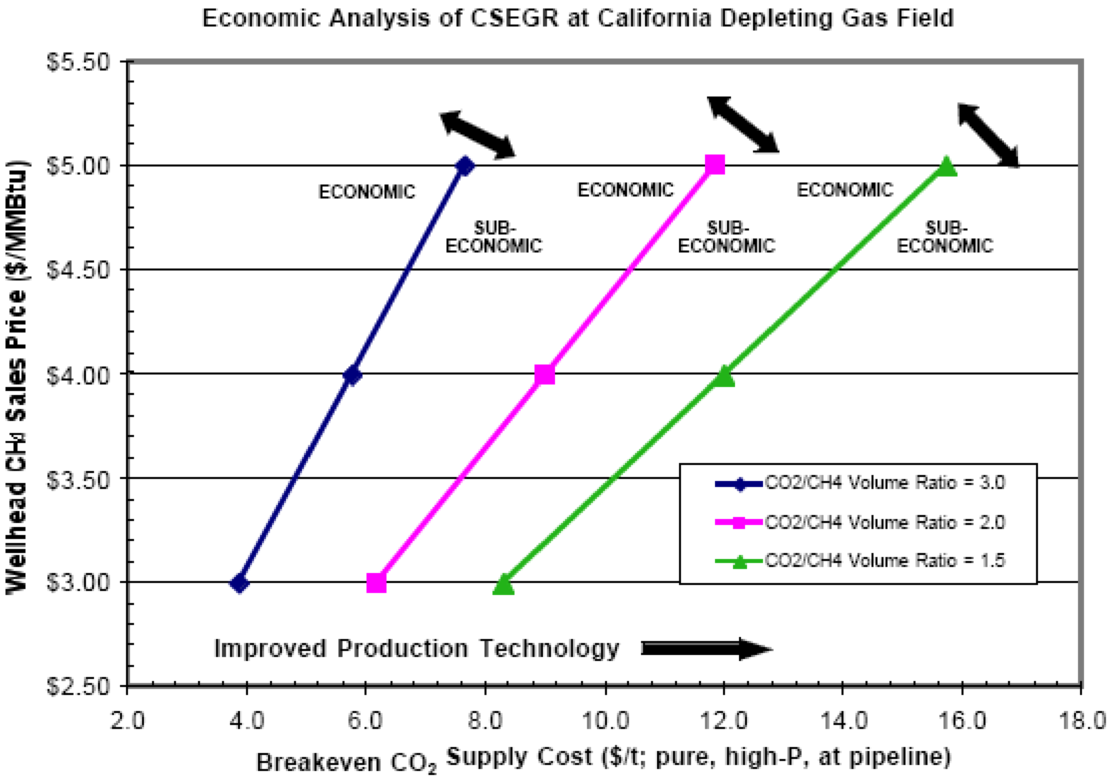

Figure 3-8: Gas supply costs for a Californian gas field with EGR as a function of CO_2 supply costs and ratio of CO_2 injected to methane produced (/Oldenburg et al. 2004/)

Figure 3-9 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.

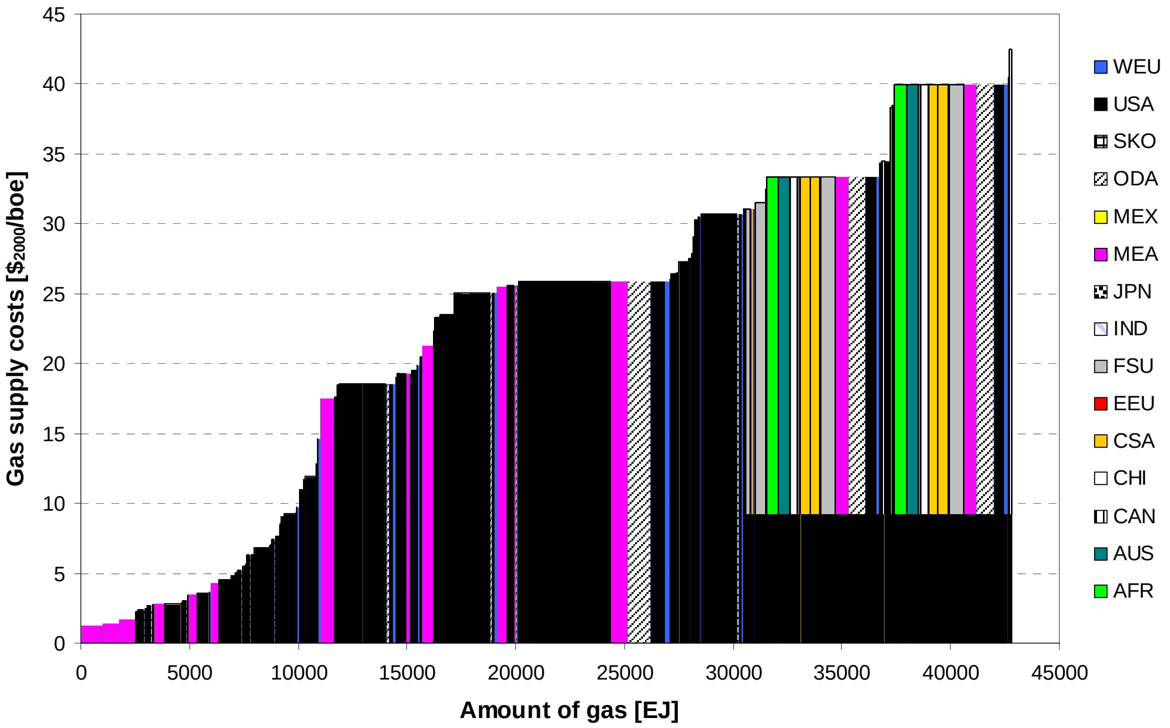

Figure 3-9: Global gas supply cost curve including conventional and unconventional gas (excluding gas hydrates) for reserves and resources at the end of 2005[10]

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[10] Information on unconventional gas resources is reported for the end of year 2004. Assuming 2005 production figures for coal-bed methane (the only unconventional gas resource being utilized) is in a similar range has in 2004 (1.5 PJ), it seems admissible to neglect this amount in the graph compared to the total coal-bed resources of 6,490 EJ.

3.3 Oil

Oil is with a share of 38 % (163 EJ) in global primary energy consumption in 2005 the most important energy carrier in the world (/BP 2006/). After World War II the global oil demand has been growing rapidly (Figure 3-3). The Arab oil embargo in 1973 and the Iranian Revolution in 1979 caused oil price shocks, which in turn initiated in the oil importing countries 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 China and India (Figure 3-10).

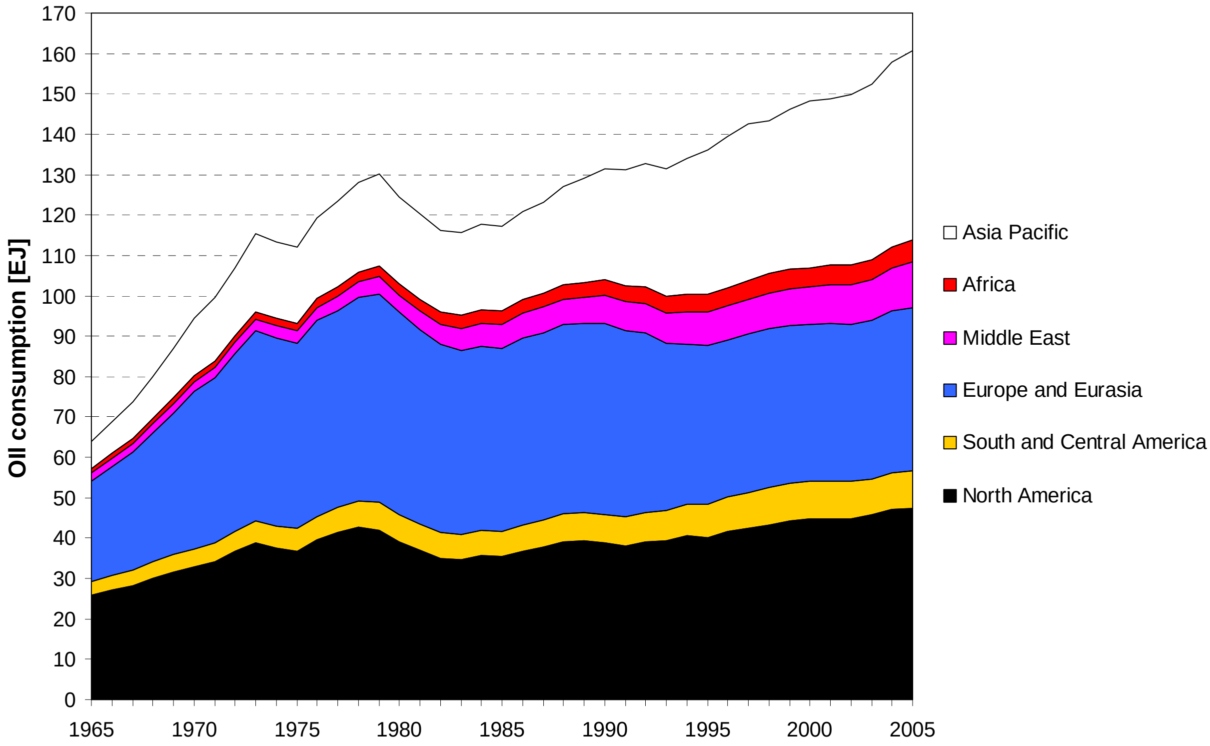

Figure 3-10: Historic oil consumption by world region (/BP 2006/)

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[11]). 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 sands (also called tar sands), extra-heavy oil and oil shales.

The general structure of the oil supply sector used in this analysis is displayed in Figure 3-11. Conventional oil resources have been divided in a similar way as for natural gas

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

in the categories recoverable reserves, enhanced oil recovery (EOR) and resources. Each resource category is presented by three costs 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 world region. As a by-product of conventional oil production natural gas (so-called associated gas) can be obtained.

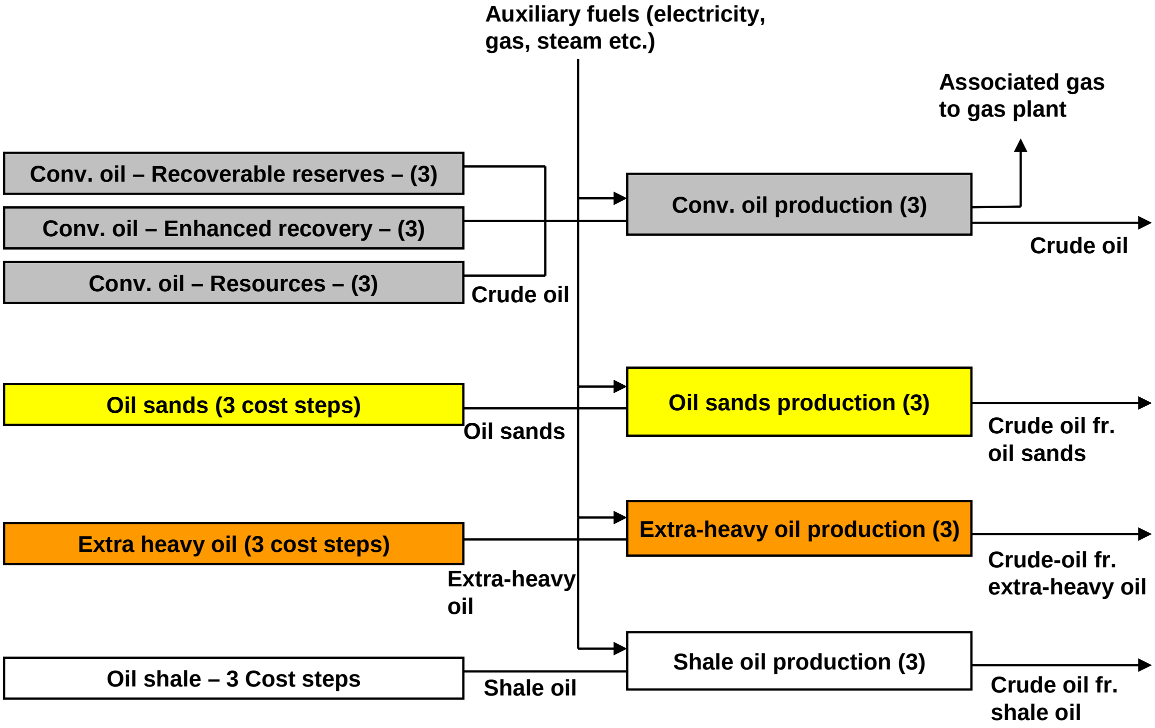
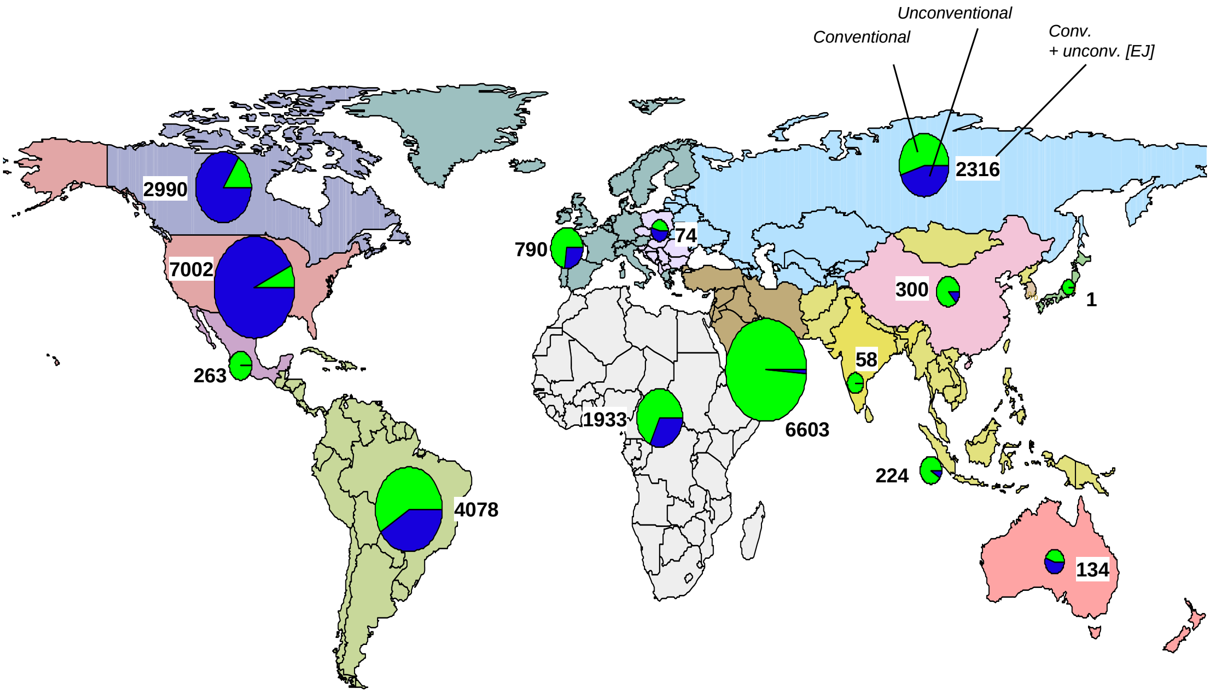


Figure 3-11: Oil supply module

An overview on the global distribution of conventional and unconventional oil deposits is given in Figure 3-12. 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 26,767 EJ at the end of 2005.



Conventional [EJ]		Unconventional reserves + resources [EJ]			Total [EJ]	Production 2005 [EJ]
Reserves	Resources	Tar sand	Extra heavy oil	Shale oil		
10 197	4 091	3 117	1 616	7 746	26 767	163

Figure 3-12: Distribution of conventional and unconventional oil deposits at the end of 2005 (/WEC 2004/, /USGS 2000/, /BP 2006/)

3.3.1 Conventional oil

163 EJ of conventional oil have been produced in 2005. Ca. 34 % of this production comes from offshore fields. Total conventional reserves and resources added up to 14,288 EJ at the end of 2005. Middle East is the region with the highest amount of conventional oil deposits (6,880 EJ), followed by Central South America (2,280 EJ), the Former Soviet Union (1,434 EJ) and Africa (1,450 EJ). For conventional oil three categories have been considered here: recoverable reserves, enhanced oil recovery and contingent plus undiscovered resources. The estimated available oil amounts from these categories are summarized in Table 3-9. Based on the global oil consumption in 2005, the static lifetime of conventional oil recoverable reserves was around 43 years in 2005, including enhanced oil recovery and oil resources the static lifetime rises to 88 years.

Table 3-9: Regional distribution of conventional oil reserves and resources at the end of 2005 (/WEC 2004/, /USGS 2000/, /BP 2006/)

EJ	AFR	AUS	CAN	CHI	CSA	EEU	FSU	IND	JPN	MEA	MEX	ODA	SKO	USA	WEU	Total
Recoverable Reserves	522	20	344	116	1235	10	388	26	0	3922	74	59	0	148	95	**6960**
EOR past production	116	8	39	42	128	11	211	9	0	370	48	45	0	288	63	**1377**
EOR future production	144	6	90	35	319	4	114	8	0	1017	24	19	0	47	32	**1859**
EOR total	260	14	129	76	447	14	325	17	1	1388	72	64	0	335	95	**3237**
Resources	535	29	16	69	599	9	569	15	0	1197	117	78	0	473	386	**4091**
Total	**1317**	**62**	**489**	**261**	**2280**	**34**	**1283**	**58**	**1**	**6506**	**263**	**201**	**0**	**956**	**576**	**14288**

Recoverable Reserves

Global recoverable reserves of conventional oil including natural gas liquids (NGL) have been estimated based on /WEC 2004/ to be around 6,960 EJ at the end of 2005[12]. The reserve figures for the OPEC member states are based there on the official sources. However, in the late 80s there were huge increases in the announced reserve quantities for several OPEC countries. In the Middle East, oil reserves of the OPEC members rose from 2,154 EJ in 1981 to 3,896 EJ in 1990 /BP 2006/. These sudden reserve additions go along with a change in assignment of the production quota to the OPEC members. The new allocation rules took into account beside the production capacity of each member state also its oil reserves. Therefore, it is suspected that some of the reserve additions, which have occurred in the late 80s, are based on strategic considerations, and do not reflect the real reserve situation in these countries. Some petroleum analysts believe that oil reserves of the OPEC are much lower. For example, based on estimation by /Salameh 2004/ the recoverable oil reserves of the Middle East would not be 3,922 EJ as based on official sources, but around 2,381 EJ. A lower amount of recoverable oil reserves implies also a lower potential of enhanced oil recovery from future production of 617 EJ, so that the overall conventional oil reserves of the Middle East would be with 4,565 EJ ca. 30 % lower than the 6,506 EJ given in Table 3-9.

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[12] /WEC 2004/ states the reserves at the end of 2002. To obtain an estimate for the reserves at the end of 2005, the production in the years 2003-2005of 481 EJ has been subtracted from the 2002 reserves of 7,723 EJ.

Outside the Middle East, Venezuela has the highest conventional reserves (1,235 EJ or 17 % of global reserves) excluding extra-heavy oil reserves (with a gravity of less than 8°API), which have been included in the unconventional resources (section 3.3.3).

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. Usually, the recovery factor from oil fields is practice with an average recovery factor of ca. 35-40 % much lower, since the technological efforts to reach the ultimate recovery are - depending on the oil price - not cost-effective /IEA 2005/.

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 a 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 oil fields of the world would account for an amount corresponding to one year of global oil production.

To estimate the potential from enhanced oil recovery methods it has been assumed here that the average recovery for conventional oil fields without EOR is around 40 %, while it has been assumed here that it can be increased further by 10 % to 50 % by means of EOR. The calculation method is similar to the one presented above for EGR. EOR may be applied to existing or future oil fields, but also to already abandoned oil fields. For the latter ones, the supply costs are probably much higher depending on how much of the oil rig installation is still in place, especially in the case of offshore oil fields. Therefore, the potential production from EOR has been divided into EOR from past production and future production. On a global level, the potential of EOR from future production is 1,859 EJ. Since past production is excluded, it might be considered as a conservative estimate. Applying EOR to the past production yields additional 1,377 EJ. Thus, the total potential for EOR can be estimated to be around 3,237 EJ.

Resources

Estimates of mean 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/). As for natural gas resources, the mean value is used to estimate the sum of contingent and undiscovered oil resources. Thus, global oil resources are estimated to be around 4,091 EJ. For a 95% probability of existence /USGS 2000/ states a resource amount of 2,392 EJ, while for a probability of existence of at least 5 % the resource estimate increase to 7,243 EJ. The global distribution of the oil resources is similar to the one of the reserves with the Middle East being the region with the largest resource amount (1,197 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 2002/, 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 to 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 3-10 for some countries, as far as available in the literature. Reserve amounts of associated gas are included in the reserve figures for recoverable gas reserves, since statistics explicitly differentiating between associated and non-associated gas reserves are not publicly available.

Table 3-10: 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

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 12,479 EJ (Table 3-11) in the same range as the conventional amount of oil (14,288 EJ, Table 3-9). 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 oil shale in the USA and in oil sands in Canada (Table 3-11).

Table 3-11: 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**

3.3.3 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 (CSS) and the steam assisted gravity drainage (SAGD). In the CSS method, steam is injected in the deposit and 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 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 with 2,466 EJ in Canada (79 %). For more than 35 years oil sands are produced in the Canadian province Alberta. In 2004, 2,183 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.

3.3.4 Extra-heavy oil

Extra-heavy oil is in its density similar to oil sands (> 1 g/cm^3), 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. The cyclic injection of steam in the vertical well (cyclic steam stimulation - CSS) or the steam assisted gravity drainage (SAGD), as described in the previous section for oil sands, are also applied for the production of extra-heavy oil. To avoid the high energy costs for the steam, also “cold methods” to extract extra-heavy oil, e.g. by solvents, are being explored.

At the surface, the produced extra-heavy oil is diluted by a solvent, so that it can be transported by pipeline. Similar to bitumen from oil sands, the extra-heavy oil needs to be upgraded before feeding it to a refinery. Alternatively, the extra-heavy oil extracted from the reservoir is emulsified with water (70 % natural bitumen, 30 % water, 1 % surfactants), the resulting product being called Orimulsion®[13]. Orimulsion can be pumped, stored, transported and burnt in conventional boilers with only minor modifications. In addition to being used in conventional power plants using steam turbines, Orimulsion can be used in diesel engines for power generation, in cement plants, as a feedstock for integrated gasification combined cycle (IGCC) and as a ‘reburning’ fuel (a method of reducing NO_x by staging combustion in the boiler) /WEC 2004/.

Extra-heavy oil reservoirs nearly exclusively exist in Venezuela, 1,610 EJ of 1,616 EJ of global reserves are found there. Global production was around 1,226 PJ in 2002.

3.3.5 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

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[13] Orimulsion is a registered trademark of Bitúmenes Orinoco S.A.

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 hydro cracking 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 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 surface retort process is estimated by /Johnson, et al. 2004/ to be around 0.194 PJ/PJ_{Oil}, which is quite similar to the energy demand for the ICP process (0.2 PJ/PJ_{Oil} /Bartis, et al. 2005/). 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 % 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 7,746 EJ for more than fourth of the global oil resources. The majority of global shale oil resources are located with 6,045 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 shale oil per day operate in Estonia. In China, the installed capacity of oil production from oil shale comprised 90,000 tons of oil per year /Johnson et al. 2004/.

3.3.6 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 3-12.

Supply costs for EOR are ranging from 3-8 \$/boe[14] 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 3-12: 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 and 3.5 \$/GJ, excluding the costs for natural gas, 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.

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[14] 1 boe or bbl (barrel of oil) equals 159 liters of oil, 1/7 ton of oil or 5.98 GJ.

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

The resulting global oil supply cost curve is displayed in Figure 3-13. The supply costs displayed there are costs at the wellhead. For the unconventional oil sands, extra-heavy oil and oil shale, the energy input (mainly natural gas) required for the different extraction and upgrading processes is not included in the given costs here, since these costs depends on the assumed gas supply costs and thus the resource situation for natural gas. Assuming natural gas costs of 3 $\$/GJ_{gas}$ and auxiliary gas requirements as stated in section 3.3.2, the costs for natural gas add 0.4-0.6 $\$/GJ_{oil}$ to the supply costs of oil sands, 0.6 $\$/GJ_{oil}$ to the ones of extra-heavy oil and 0.3 $\$/GJ_{oil}$ to the costs of oil shale production.

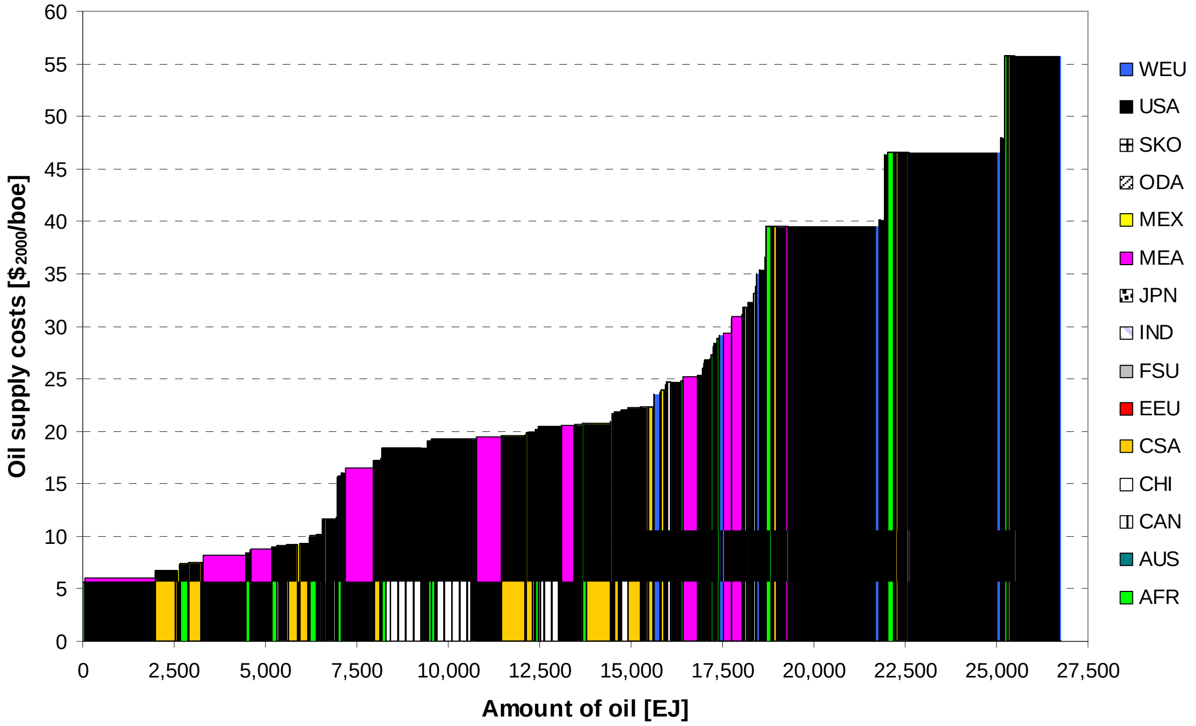

Figure 3-13: Global oil supply cost curve including conventional and unconventional oil at wellhead for reserves and resources at the end of 2005[15]

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[15] Information on unconventional oil reserves are from 2002 /WEC 2004/. Since production levels in 2002 for oil sands, shale oil and extra-heavy oil have been a factor 1000 smaller than the corresponding reserves, the production in the years 2003 to 2005, which would have to be subtracted from the 2002 reserve quantities, are expected to change the graph only insignificantly.

3.4 Uranium

437 nuclear power plants worldwide have been in operation or under construction at the end of 2006. Total installed net capacity of these plants equals 369 GW_e (/atw 2007/). Global demand for uranium has been around 68,100 t in 2005 /NEA 2006/. This consumption is only partially covered by 40,000 t through uranium mining, whereas the remaining uranium supply stems from secondary sources as uranium stockpiles or disarmed nuclear weapons. The global production and consumption of uranium are shown in Figure 3-14. There have been two phases of extensive uranium exploration and production; one in the 50s of the last century driven by the demand for nuclear weapons and one in the 1970s due to the rapid build-up of large commercial nuclear capacity as reaction to the oil embargo in 1972. Overexpansion of the uranium supply infrastructure during the 1970s led to limited exploration and the closure of operating mines during the past 20 years or so. Further reasons are the much slower growth of commercial nuclear power than was originally anticipated as well as the mentioned reduction of civil uranium stockpiles and the disarmament of nuclear weapons.

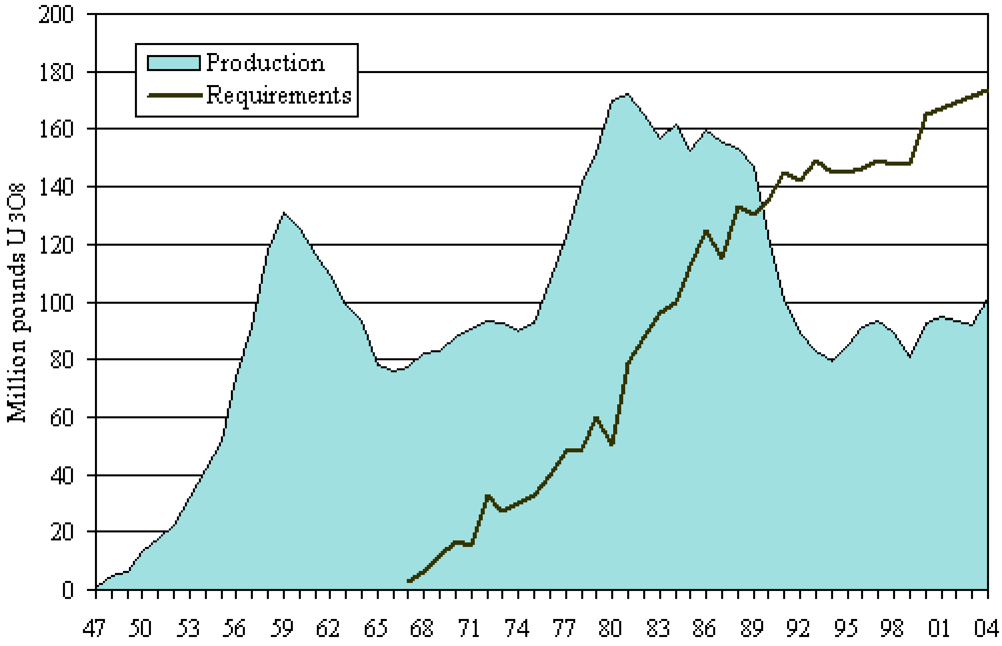

Figure 3-14: Global uranium production and consumption (/Combs 2004/)

Natural uranium occurs as a mixture of the two isotopes U-235 and U-238, from which U-235 is the fissionable isotope necessary for the nuclear energy production. U-235 is the only fissionable element occurring in the nature. The low concentration of the isotope U-235 in natural uranium (typically around 0.7 %) in most cases impedes the direct use of natural uranium in nuclear power plants, only heavy-water reactors (using heavy water (D_2O)

as moderator) can use natural uranium as fuel. More common light water reactors require uranium with a concentration of U-235 in the range of 3.5 to 4 %. Therefore, an enrichment process is required to increase the concentration of this isotope in the uranium.

In the remaining part of this section, an overview of the global uranium resource situation, the extraction costs as well as the further processing steps from the mine to the nuclear fuel rod is given.

3.4.1 Conventional uranium resources

Natural uranium resources are distinguished in conventional and unconventional resources. Conventional resources are further divided into reasonable assured resources (RAR), inferred resources (IR), prognosticated resources and speculative resources (SR).

Reasonable Assured Resources (RAR)

Reasonable assured resources (RAR) are uranium deposits, which are proven to exist with a high degree of certainty and which can be extracted with known mining technologies. Depending on the extraction costs, these uranium resources are further specified in the three categories less 40 \$/kg U[16], 40-80 \$/kg U and 80-130 \$/kg U extraction costs. Reasonable assured resources with extraction costs below 40 \$/kg U are also referred to as uranium reserves. Global uranium amounts in the category RAR are estimated to be 3,297 kt U in 2005. For illustrating the energy content of 1 kg uranium: assuming a burnup rate of 48 MW-d/kg ihm[17] and a feed factor of 11.2 kg U_3U_8/kg ihm, one kilogram of natural uranium can produce 104 MWh of thermal energy in a light water reactor, which yields 38 MWh of electricity assuming a net efficiency of 37 % of the nuclear power plant. Reprocessing the nuclear fuel one time increases overall thermal energy gained from one kilogram of natural uranium to 164 MWh and the amount of electricity to 61 MWh.

Uranium is mined today depending on the geological conditions by different methods. Most of the uranium is mined today by open pit or underground mining. Uranium is also obtained as by-product of other mining activities, e.g. mining of copper, silver or gold in Australia.

Another mining method is the so-called in-situ leaching (ISL). In this method, a leaching liquid (alkaline or acid depending on the rock) is pumped from an injection well through the ore body and returned to the surface by a second well. The uranium is removed from the liquid by precipitation, electrochemistry, or other means. The leaching liquid is then returned to the ore body and the process is repeated. Thus, up to 80% of the uranium

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[16] The abbreviation U denotes natural uranium.

[17] ihm: initially heavy metal

contained in the ore body can be extracted. ISL eliminates the need to remove large quantities of ore from the ground and to transport it to the mill, thereby minimizing surface disturbance. ISL also eliminates the need to dispose the tailings or waste rock. However, for ISL to be effective, the ore body must be permeable (e.g. sand stone) to the flow of the leaching liquid. Furthermore, the ISL site must be located in such a way that the groundwater cannot be contaminated. ISL is used for 85 % of U.S. uranium production. Worldwide, approximately 16 % of uranium production uses ISL, including all of the production in Uzbekistan and Kazakhstan.

For ores having a low uranium concentration, heap leaching (HL) is an economic method to extract the uranium. Therefore, a leaching liquid is fed into the top of the mined ore heap and collected at the bottom of the heap, from where the liquid is pumped to a processing plant. Heap leaching avoids large processing capacities of ore having only a low uranium concentration. In Europe, heap leaching was used until 1990 in East Germany and in Hungary.

In-place leaching (IPL) differs from in situ leaching by the fact that the leaching is applied to the broken ore in the underground mine. For the reasonable assured resources underground and open pit mining as well as in-situ leaching are the most important mining methods. Large quantities of uranium can also be mined as by-product of other mining activities (Table 3-13).

Table 3-13: Reasonable assured resources by mining type (in t uranium)

Mining type	< 40 US-$/kg	< 80 US-$/kg	< 130 US-$/kg
Open pit mining	275,296	467,535	614,163
Underground mining	553,955	835,003	1,223,409
In-situ leaching	360,936	401,936	445,033
Heap leaching	30,668	39,887	50,287
In-Place leaching	300	300	300
By-product mining of other minerals	570,100	587,900	587,900
Non-specified	156,128	310,782	375,597
Total	**1,947,383**	**2,643,343**	**3,296,689**

Inferred Resources (IR)

Inferred resources refers to uranium that is inferred to occur due to direct geological evidence, but due to missing further exact information cannot be included in the RAR category. Inferred resources in the world have been around 1,446 kt U in 2005.

Prognosticated Resources (PR)

Prognosticated resources describe uranium deposits that are assumed to exist mainly based on indirect evidence, e.g. due to the existence of other minerals typically occurring together with uranium. Furthermore, the location of the deposit is exactly known. Global prognosticated resources have been 2,519 kt U in 2005.

Speculative Resources (SR)

Speculative resources are quantities that are thought to exist based on indirect evidence or geological extrapolations. Only the rough location of these deposits in a region is known, but not the exact position. Speculative resources are estimated to be around 7,536 kt U on a global level, of which 4,557 kt U can be produced at costs below 130 $/t U.

The global conventional and unconventional uranium resources are summarized in Table 3-14.

Table 3-14: Global uranium resources and static lifetimes at the end of 2005 (/NEA 2006/)

Uranium resources		$/kg	1000 t U	Static lifetime [a]	Cumulated [a]
Conventional resources	**Reasonable Assured Resources (RAR)**	≤40	1,947	29	29
		>40-80	696	10	39
		>80-130	654	10	48
		total	***3,297***	***48***	
	Inferred Resources (IR)	≤40	799	12	60
		>40-80	362	5	66
		>80-130	285	4	70
		total	***1,446***	***21***	
	Prognosticated Resources (PR)	≤80	1,700	25	95
		>80-130	819	12	107
		Total	***2,519***	***37***	
	Speculative Resources (SR)	<130	4,557	67	174
		>130	2979	44	44
		Total	***7,536***	***111***	***218***
	Resources	***Total***	***14,798***		***218***
Unconventional resources	**Uranium in phosphates**	60-100	22,000	324	541
	Uranium in sea water	200-1,000	4,000,000	58,824	59,365
	Thorium		ca. 4.500		
	Secondary sources (reprocessing, nuclear weapons)		378	6	6

Regional distribution of conventional resources

Total global conventional uranium resources have been around 14,798 kt U in 2005. FSU possesses with 21 % the largest share of conventional uranium resources up to extraction costs of 130 $/kg U (Figure 3-15). Further countries or regions with high shares are USA (20 %), other developing Asia (ODA, 12 %), Australia (11 %), Africa (9 %) and Canada (9 %).

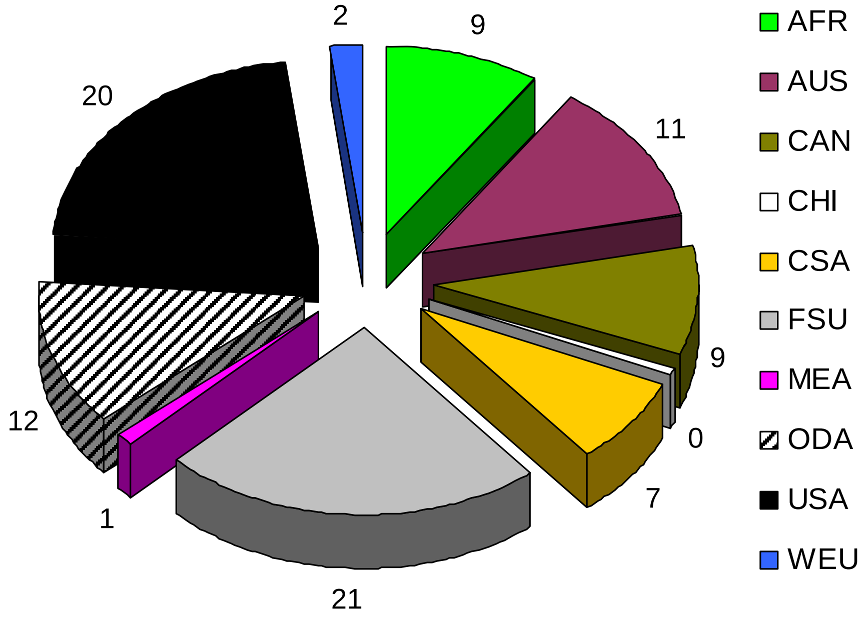

Figure 3-15: Regional distribution of conventional uranium resources as percentage in 2005

The global distribution of conventional resources in absolute terms by different cost categories is given in Figure 3-16. Resources up to 40 $/kg U are mainly found in Australia, the FSU, Africa and Canada. Resources with higher costs are more equally distributed, and can be found in addition to the mentioned regions also in Brazil, Mongolia and the USA.

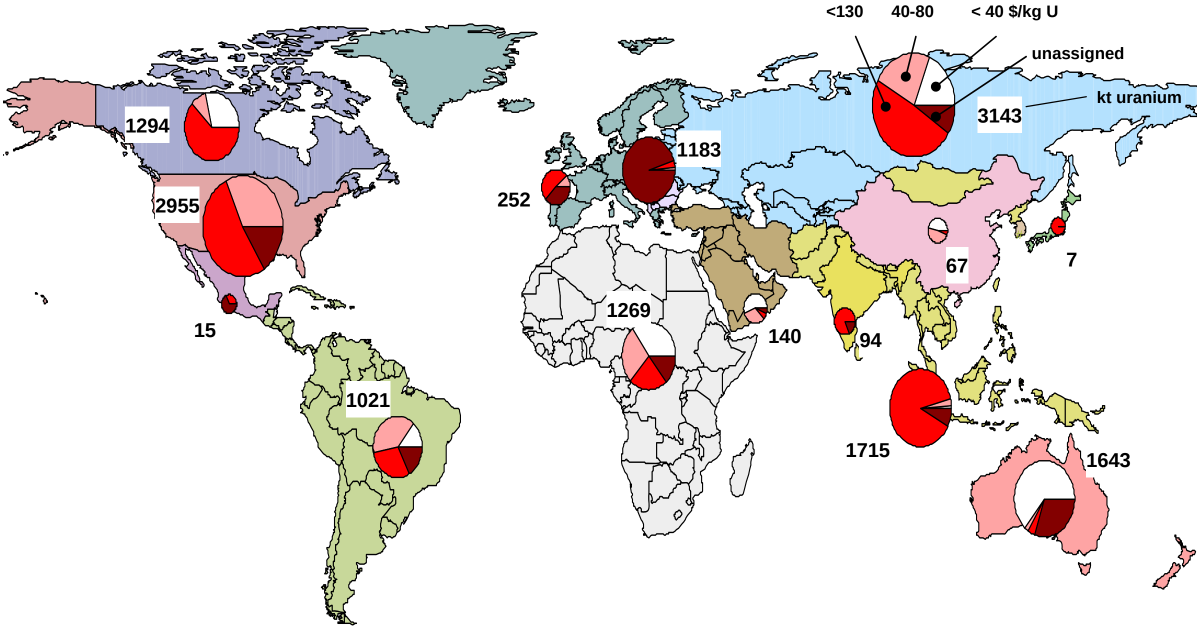

Figure 3-16: Regional distribution of conventional uranium resources in absolute terms at the end of 2005

Table 3-14 also shows the static lifetime of the different resource categories based on an annual global consumption of 68 kt U. With this consumption the RAR category up to 40 $/kg U would last for 29 years, the RAR amounts for 48 years. Taking into account also the inferred, prognosticated and speculative resources, conventional uranium resources would last for 218 years. In contrast to conventional oil and gas resources, where exploration is an ongoing process, extensive exploration efforts for uranium have occurred only in two cycles: one after World War II driven by the uranium demand for nuclear weapons and one in the 1970s due to the build-up of nuclear power plants in the aftermath of the oil embargo. It can be assumed that new exploration efforts for uranium would lead to higher amounts of conventional uranium resources in all categories.

Another factor that may expand the lifetime of the uranium resources is the fact that uranium today is used overwhelmingly in the LWR fuel cycle, where only approximately 1.1 to 1.5 % of the ultimate energy of the mined uranium is extracted via fissioning of U-235 and the small amounts of Pu-239 bred in situ. The rest of the uranium remains either in the spent fuel or in the depleted uranium after enrichment. Using fast breeder instead of conventional nuclear reactors, the static lifetime of conventional uranium resources would reach with 20,000 years a totally different time dimension compared to the 218 years for the conventional fuel cycle.

3.4.2 Unconventional uranium resources

Unconventional uranium resources are defined as deposits having only a very low uranium concentration or being only a minor by-product. Examples for unconventional resources are uranium in phosphates or in seawater. Secondary resources, in contrast to the primary resources obtained through mining, also fall in the group of unconventional uranium resources. Secondary resources are the reenrichment of depleted uranium tails obtained at as waste product of the enrichment process, reprocessing of used nuclear fuel (uranium and plutonium), high enriched uranium (HEU) from former nuclear weapons. Uranium stocks hold as strategic reserve by the owners of nuclear power plants are also considered as secondary resource.

Uranium in phosphates

Global uranium resources extracted from phosphates are estimated to be around 22 kt U (Table 3-14). Due to high extraction costs in the range of 60-100 $/kg U this uranium source is under current market conditions economically not attractive. Existing facilities for extraction uranium from phosphates have been closed in the 1990s in Belgium, the FSU and the USA.

Uranium in sea water

Uranium is dissolved in seawater at 3 mg/t and represents a well-known resource of 4 billion t, more than 300 times the known land-based resource. Estimates of recovery costs have been in the neighborhood of 200-1000 $/kg U, although these estimates are highly speculative. The uranium content of the oceans is relatively constant, and large-scale extraction can be done without local depletion of the resource. Because only approximately 3 % of the global population lives in landlocked countries without access to sea water, extraction of uranium from seawater can be considered, due to its vast resource base and the access of most countries to sea water, as an upper bound on the supply costs for uranium. Hence, no producer will be able to enforce higher prices on a long-term basis.

Tailings from the enrichment process

Tail streams obtained during the enrichment process of the uranium fuel production (see section 3.4.3) still contain a significant amount of the fissionable U-235 isotope. Approximately 1.2 to 1.35 Mt U contained in tail streams are produced each year having a U-235 concentration of 0.3 % or lower. Reenriching this tail uranium to a concentration level of 0.7 % as in natural uranium could substitute 440,000 to 500,000 t U. Some depleted uranium is drawn from these stockpiles to dilute high-enriched uranium from nuclear weapons programs and deferred for use in civil reactors. The dilution factor is around 25:1 (weapon material: depleted uranium).

Reprocessing of spent nuclear fuel

The unused uranium of the spent nuclear fuel rods as well as the small amount of plutonium produced in a nuclear power plant can be reprocessed to a mix oxide (MOX) fuel element. The one time recycling of plutonium in form of MOX increases the energy yield of the original uranium by 12 %, the concurrent recycling of the spent uranium increases the energy yield of the original uranium by 22 % in total. Depending on the reactor type, the charging of existing light water reactors with MOX fuel elements can be as high as 50 %. New LWR reactors as the European Pressurized Reactor (EPR) can be entirely loaded with MOX elements. Due to reprocessing of spent nuclear fuel ca. 1,100 t uranium were saved in the year 2005. Reprocessing plants exist in Belgium, France, Japan and the UK.

Uranium from nuclear weapons

High enriched uranium (HEU) from nuclear weapons is a further uranium source for nuclear power generation. Due to the nuclear disarmament agreement between Russia and the USA, ca. 674 t of HEU will be released between 1993 and 2013. This amount of HEU corresponds to a total of 206,000 t natural uranium or an annual production of ca. 9,000 t U. In addition, the USA and Russia agreed to release 68 t plutonium from nuclear weapons until 2025, which corresponds to 7,000 to 8,000 t natural uranium.

3.4.3 Uranium processing

Starting from the mined uranium several processing steps are necessary to reach the nuclear fuel rod. These steps are:

- milling,
- refining and conversion,
- enriching and
- fuel rod production.

After mining, the uranium is further processed in a milling process to uranium oxide (U_3U_8), also called yellow cake. The first process step of milling consists of crushing the uranium ore, which is then mixed with water to produce a slurry. By adding sulfuric acid the uranium reacts to UO_2^{++}. In the case of ISL, this processing step already occurs as leaching process in the mine. Yellow ammonium diuranate is then precipitated from the solution by adding gaseous ammonia. After dewatering, one obtains uranium oxide (U_3U_8), the so-called yellow cake, with a purity being higher than 99 %.

Since in natural uranium the concentration of the fissionable uranium isotope U-235 is with 0.7 % too low (the rest being mainly U-238 with 99.27 %) for most nuclear plants, the concentration of the U-235 isotope has to be increased by an enrichment process. For enrichment the yellow cake (U_3U_8) has to be converted to a gaseous form, the most convenient form to achieve this is the conversion of the uranium oxide to uranium hexafluoride (UF_6). Conversion plants are operating commercially in United States, Canada, France, the United Kingdom and Russia. The plants are in most cases not directly linked to a uranium mine, but operate independently by buying uranium oxide and selling the produced uranium hexafluoride. The production of the uranium hexafluoride consists of several reaction steps, at which at the same time also impurities in the uranium are removed.

The chemical properties of the two isotopes U-235 and U-238 are identical, so that for enriching the concentration of the fissionable U-235, differences in the physical properties of the isotopes, namely their different mass, is used. Two types of enrichment processes are used on a commercial scale: the gaseous diffusion process and the centrifuge process. In the gaseous diffusion process, the gaseous UF_6 is pressed through a porous membrane. Since the U-235 isotope is lighter, it moves faster through the membrane. The UF_6, which diffuses through the membrane, is thus slightly enriched, while the gas which did not pass through is depleted in U-235. This process is repeated many times in a series of diffusion stages called a cascade. Each stage consists of a compressor, a diffuser, and a heat exchanger to remove the heat of compression. The enriched UF_6 product is withdrawn from one end of the cascade and the depleted UF_6 is removed at the other end. The gas must be processed through some 1400 stages to obtain a product with a concentration of 3 % to 4 % U-235.

In the centrifuge process, the UF_6 is fed into a series of vacuum tubes, each containing a rotor. When the rotors are spun rapidly, the heavier molecules with U-238 increase in concentration towards the cylinder's outer edge. There is a corresponding increase in concentration of U-235 molecules near the center. The enriched gas is drawn off and goes forward to further stages while the depleted UF_6 goes back to the previous stage. Centrifuge stages normally consist of a large number of centrifuges in parallel. Such stages are then arranged in cascade similarly to those for diffusion. In the centrifuge process, however, the number of stages may only be 10 to 20 instead of a thousand or more for diffusion.

The capacity of enrichment plants is measured in terms of separative work units, or SWU. The SWU is a function of the amount of uranium processed and the degree to which it is enriched (i.e., the extent of increase in the concentration of the U-235 isotope relative to the remainder). For instance, to produce one kilogram of uranium enriched to 3 % U-235 requires 3.8 SWU, if the plant is operated at a tails assay of 0.25 %, or 5 SWU if the tails assay is 0.15 % (thereby requiring only 5.1 kg instead of 6.0 kg of natural U feed). Global enrichment capacities have been around 51.120 t SW/a. The annual uranium consumption of a light water reactor (1000 MW) requires on average 0.1 to 0.15 t SW.

Energy costs are an important factor of the enrichment costs. In contrast to the high energy need of 2500 kWh/kg SW of the diffusion process, the centrifuge process consumes only 50 kWh/kg SW.

The enrichment process can be viewed as a process transforming the entering feed stream of uranium into two output streams: a product stream with an enriched U-235 concentration compared to the feed stream and a tail stream with a lower U-235 concentration. The U-235 concentration of the tail stream has significant impact on the one hand on the necessary uranium feed stream and on the other hand on the required separation work. If the concentration of U-235 decreases from 0.3 % to 0.1 %, the natural uranium feed stream can be reduced by 30 %, but at the same time the separation work increases by 70 %. The impact of the tail concentration on the required uranium feed stream and the energy consumption of the enrichment process is displayed in Figure 3-17.

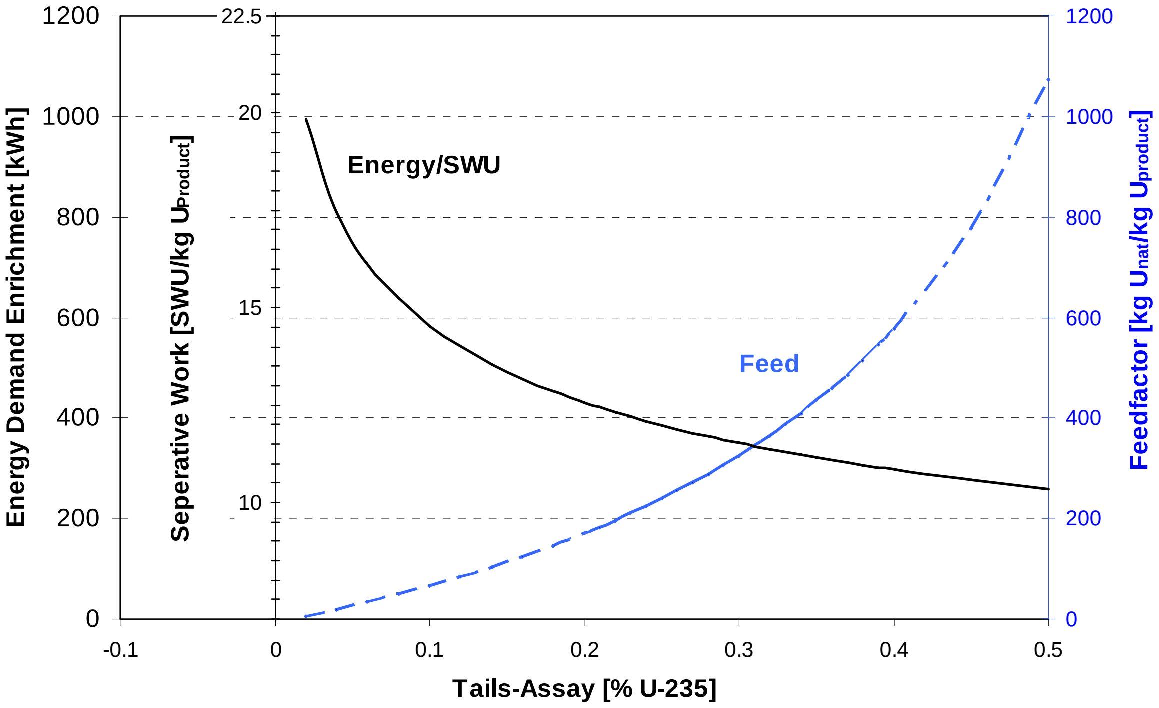

Figure 3-17: Impact of the U-235 concentration in the tail stream on feed stream and energy demand of the enrichment process

For producing the nuclear fuel rod, the gaseous UF_6 is converted in a chemical reaction to a powder of UO_2, which is then pressed to pellets of 2-3 cm length and 1 cm diameter. The pellets are refilled in a cladding rod of circolay of 4-5 m length and closed at the end by welding. A nuclear fuel element consists of up to 250 of these nuclear fuel rods.

The final nuclear fuel rod costs are around 1858 €$_{2005}$ per kg HM (heavy metal) assuming natural uranium costs of 60 $/kg U. A breakdown of the costs on the uranium supply costs and the different processing steps is given in Figure 3-18. Both, the uranium costs and the enrichment process, are with shares of 36 % and 37 %, respectively, the two largest cost contributors.

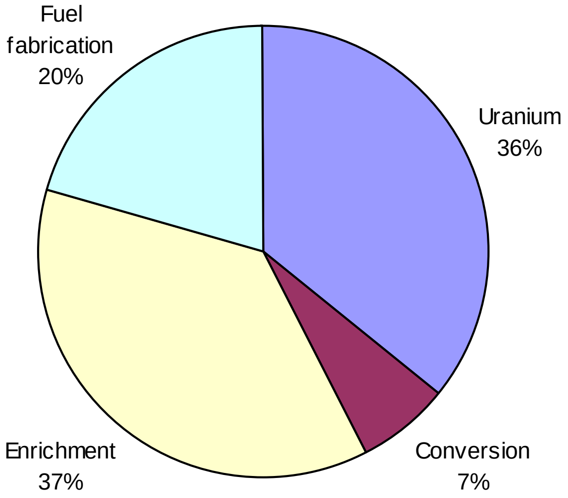

Figure 3-18: Breakdown of final nuclear fuel rod costs on uranium supply and processing steps in 2005

3.4.4 Uranium Supply costs

The global supply cost curve for conventional natural uranium resources up to extractions costs of 130 \$/kg U is shown in Figure 3-19.

Conventional uranium resources up to supply costs of 40 \$/kg U are primarily found in Australia, the Former Soviet Union (FSU), Africa and Canada. Outside of these regions at higher extraction costs significant resources are also located in the USA, Central South America (CSA) and Asia. Based on an analysis by /Pool 2004/, uranium resources up to supply costs of 40 \$/kg U have been further divided in the three cost categories: < 19, 19-27 and 27-40 \$/kg U. To give an impression of the uranium costs compared to fossil fuels, the costs per \$/kg U can be converted to costs in terms of \$/boe taking into account that 1 kg U produces approximately 104 MWh of thermal heat or 63 boe. Then, costs of 130 \$/kg U are equivalent to 0.2 \$/boe and at least by a factor of 10 lower than the range of supply costs for natural gas and oil.

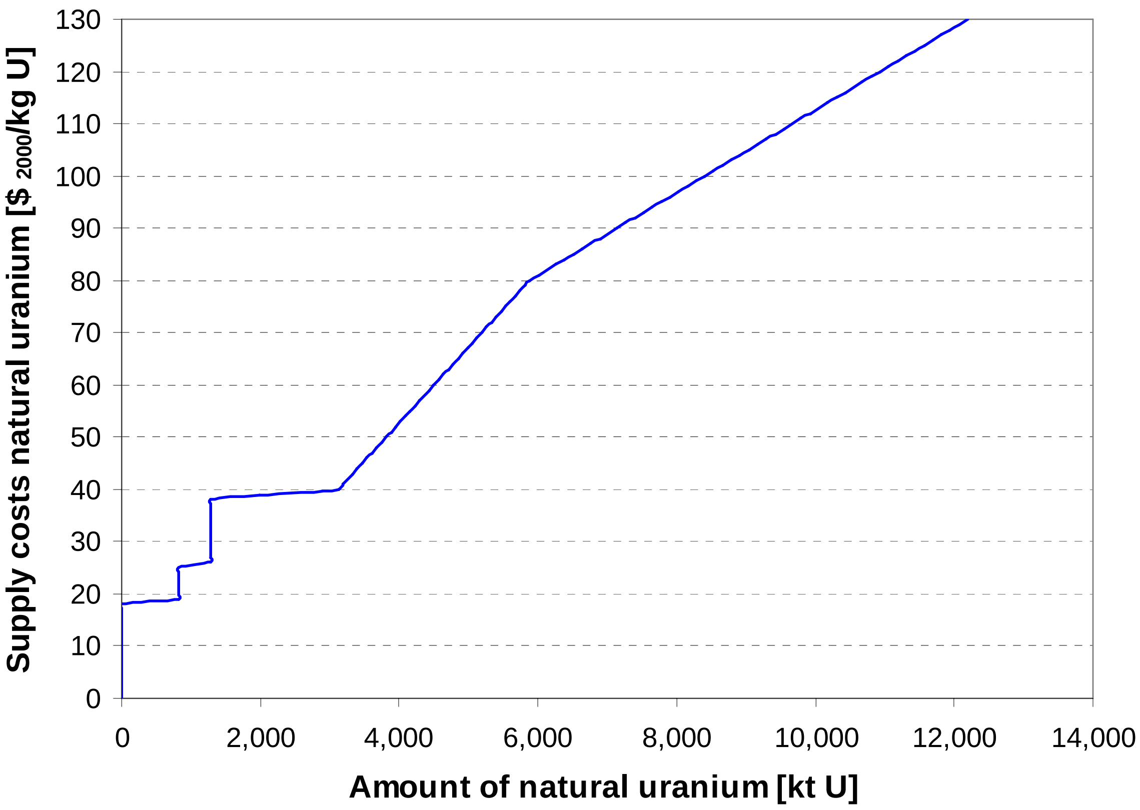

Figure 3-19: Global supply cost curve for conventional uranium resources at the end of 2005

4 Energy transport

The energy carriers coal, oil, gas and uranium 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 Coal

Coal is typically transported by rail or ship[18]. Ship transport means either transport by barges on inland waterway or ocean transport across regions by large vessels, such as Panamax (75000 dwt[19]; maximum dimension fitting through the Panama canal) or Capesize (170000 dwt) vessels. Ca. 16 EJ of coal have been traded between the world regions, as defined in this report (section 2.3), 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 refers to coking coal. The inter-regional trade flows between the world regions for the sum of hard and coking coal are shown in Table 4-1 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.

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[18] 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.

[19] dwt: dead weight ton

Table 4-1: Global inter-regional net coal trade (steam coal and coking coal) between world regions for the year 2005[20] 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	240		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					91	539		0	85	674	0	55
	CSA														82	657
	EEU					4					3					606
	FSU			1			26				155	2		76		287
	IND															
	JPN															
	MEA															
	MEX															
	ODA								311	433				161	19	254
	SKO															
	USA			520			2		1	101	65	12	3	46		572
	WEU										2					

4.2 Oil

Over large distances oil is typically transported via tanker or pipeline[21]. In 2005, the global oil tanker fleet comprised 7863 oil tankers (including product tankers) with a total tonnage of 353.5 Mio. 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 2005b/). These channels and also the water depth of harbor terminals may impose restrictions on the size of the tankers.

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[20] Due to incomplete information for major coal trade flows between non-OECD regions in 2005, 2004 values from /RWE 2005/ has been assumed.

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

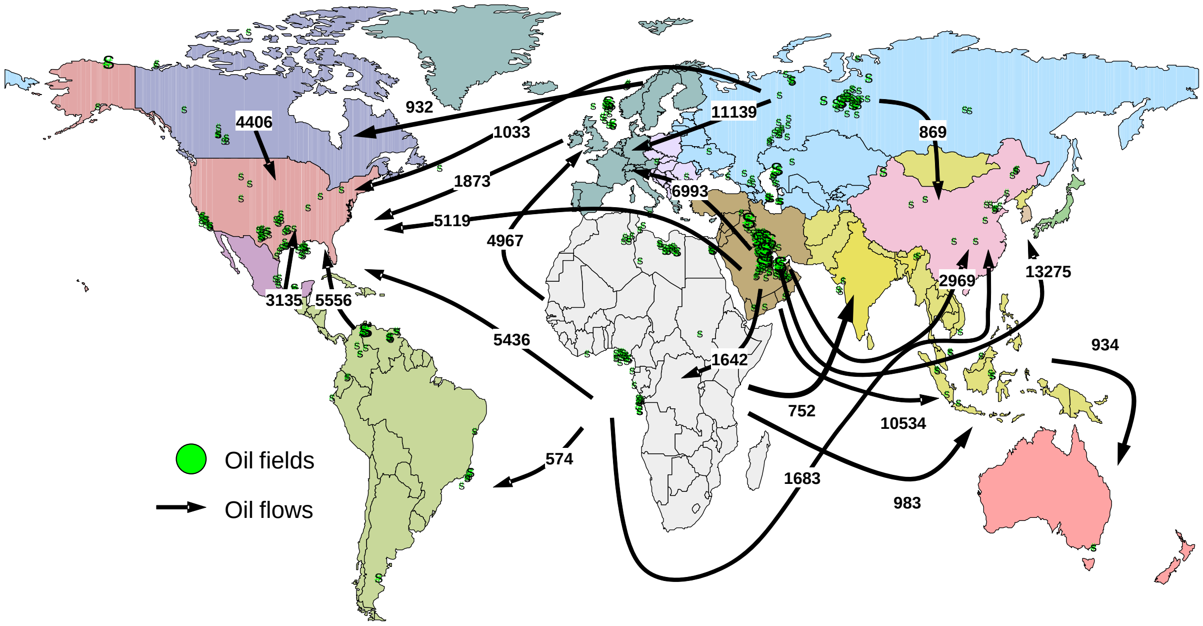

Figure 4-1: Major global oil trade flows (crude oil, natural gas liquids and refinery feedstocks) in 2005 in PJ (/BP 2006/, /IEA/)

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 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 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 the ODA region (Other Developing Asia) have been considered as future oil transport options in this analysis (/Park and Lee 2004/).

96 EJ of oil (crude oil, natural gas liquids and refinery feedstocks) or 59 % of global consumption have been traded between world regions in the year 2005 (Figure 4-1). Major oil exporters have been the Middle East, the FSU, Africa and South America.

4.3 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 19 EJ or 18 % of global gas consumption in 2005 /BP 2006/. Thereof 12 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 4-2.

Table 4-2: Existing natural gas pipeline export capacities between world regions in 2005 (/CGES 2003/, /EIA 2005a/, /GTE 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 as well as between the USA and Mexico.

The trade flows via pipeline for the year 2005 are given in Table 4-3. 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.

Table 4-3: 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 4-3 are possible pipeline links, which currently do not exist, but are possible projects being planned or under discussion. 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 4-4. 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, e.g. Japan has much higher import capacities than their average annual demand. This can be attributed to security measures to ensure sufficient import capacities also during seasonal peak demands.

Table 4-4: LNG import and export capacities in bcm/a[22] 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 3,058 PJ in 2005 the largest LNG importer in the world (Table 4-5). Major LNG producers are Indonesia and Malaysia in the ODA region with 1,260 and 1,142 PJ, respectively, in 2005. The grey cells in Table 4-5 denote again possible future options for LNG trade.

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

Table 4-5: 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														░	■

Due to the high capital costs linked to the LNG trade, especially the liquefaction terminal, LNG exporters seek to secure their investment by long-term contracts, which are typically arranged before constructing the terminal. The evolution of the publicly known contracted LNG volume over the next 30 years is shown in Figure 4-2 (/Simmons 2005/).

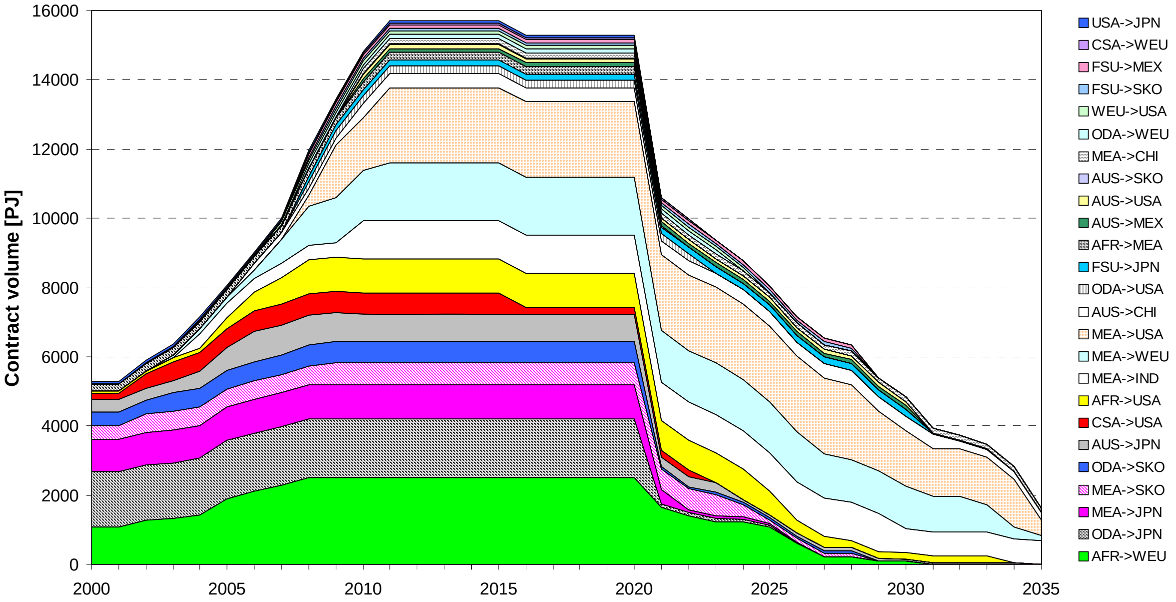

Figure 4-2: Contracted LNG flows between world regions (/Simmons 2005/)

4.4 Uranium

The market for uranium is quite different from that of any other fossil commodity. First, one cannot speak of one market, since different intermediate products (yellow cake, uranium hexafluoride, tailings from enrichment, uranium dioxide, nuclear fuel rods) are traded between different countries. For example Brazilian yellow cake is exported for conversion and enrichment, and is later re-imported as fuel rod. Secondly, the trade of uranium is closely monitored by the International Atomic Energy Agency (IAEA) due to political sensitivities and associated safeguards aimed at restricting the development of nuclear weapons. Despite this scrutiny, information on trade flows of the different uranium products is barely publicly available. Table 4-6 lists some natural uranium trade flows compiled by /WISE/ based on reports by national agencies on Australian and Canadian exports and European and US imports in 2002. Since the data do not cover the entire uranium trade, they only draw an incomplete picture of the situation. It can be noted, however, that for Europe, the Former Soviet Union (FSU) was with 46 % of uranium imports the dominating trade partner for uranium. The majority of the FSU exports to Europe in 2002 were, however, in the form of enriched uranium products (EUP) or re-enriched tails, fresh natural uranium represented only a few hundred tons /Euratom 2004/.

Table 4-6: Reported trade of uranium for the year 2002 in Mt natural uranium (/WISE/)

		Destination								
		Argentina	**Canada**	**China**	**Japan**	**Mexico**	**South Korea**	**Taiwan**	**EU**	**USA**
Origin	**Australia**		105		1,542		636		1,520	3,439
	Canada	5		213	1,366	114	217	220	3,950	4,683
	Kazakhstan								2,030	2,081
	Russia								4,900	2,436
	Uzbekistan									1,346
	South Africa									294
	Namibia									416
	Niger, Gabon								1,860	
	Other								510	

Many industrialized nations, including the Germany, UK, Japan and France, are strongly dependent on imports of uranium to fuel their nuclear power stations. Of the 17 countries that produced uranium in 2004, ten use all of their mine production domestically and five of those imported additional uranium (USA, China, Ukraine, Czech Republic and Germany). Five countries produced uranium, but do not had any nuclear power stations and therefore exported virtually all production - these are Australia, Kazakhstan, Niger, Namibia and Uzbekistan. The remaining two countries, Canada and Russia, used some of their own production domestically, but also exported substantial quantities /BGS 2005/.

4.5 Transport costs

As presented above different transport options exist for the long distance transport of coal, oil and gas[23]. 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. In this section the costs for the transport of hard coal, natural gas, LNG and crude oil between the world regions are presented. To illustrate the assumptions and input data required in the calculation of the transport costs, the derivation of the costs for LNG transport is discussed in more detail first.

4.5.1 Exemplary transport cost calculation: LNG

The transport chain of LNG typically consists of the three steps: liquefaction of natural gas in the exporting country, sea transport by LNG tanker and regasification in the import terminal. The cost assumptions for liquefaction and regasification terminals for LNG are shown in Table 4-7. 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 Mio. \$/(PJ/a) and for the regasification process to 2 Mio. \$/(PJ/a).

Table 4-7: 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

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[23] Due to limited information on trade of the different uranium products, transport costs for uranium have not been included in this analysis.

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 and 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.

The costs for tanker transport of LNG (in a similar way also for crude oil and coal) 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 a LNG tanker with a capacity of 135,000 m^3 LNG and with capital costs of 200 Mio. \$ (/Simmons 2005/) covering a distance of 10,000 km is shown in Table 4-8. 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:

Number of round trips: $$n_{trip} = \frac{24 \cdot (365 - t_{ma\,\mathrm{int}})}{2 \cdot d - t_{load} \cdot s} \cdot s$$

Total transported volume of tanker in a year: $$cap_{tot} = l_f \cdot cap_{tanker} \cdot n_{trip}$$

Specific transport costs: $$cost_{spec} = \frac{annuity + fom/100 \cdot inv}{cap_{tot}}.$$

The meaning of the symbols is given in Table 4-8. The distances between the different world regions are shown in Table 4-9. 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 4-8: 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})	10	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})	1323000	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 ($cost_{spec}$)	19.23	$/m^3$ LNG

Table 4-9: Distances between world regions in Nautical miles[24] 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															■

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[24] 1 Nautic mile = 1.852 km.

The resulting transport costs for the LNG transport including liquefaction and regasification are shown in Table 4-10. Based on the economic data in Table 4-7, liquefaction and regasification alone account for ca. 1.3 \$/GJ. For the LNG transport from Algeria (MEA) to France, Spain or Italy (WEU) these costs at the import and export terminal are the major part of the entire transport costs of 1.4 \$/GJ. Due to the relative short distance (ca. 400 km), from a cost perspective, it would have been cheaper to build a pipeline. Algeria started, however, to export its natural gas as LNG to Spain, a decision mainly based on historic circumstances /Hayes 2004/.

Table 4-10: LNG transport costs in \$/GJ including liquefaction and regasification (own calculations)

		Destination														
		AFR	**AUS**	**CAN**	**CHI**	**CSA**	**EEU**	**FSU**	**IND**	**JPN**	**MEA**	**MEX**	**ODA**	**SKO**	**USA**	**WEU**
Origin	**AFR**	■			2.9				2.4	2.9		2.3	2.5	2.9	1.8	1.4
	AUS		■		1.7					1.7		2.4		1.8	2.4	
	CAN			■												
	CHI				■											
	CSA					■						1.6			1.7	1.8
	EEU						■									
	FSU		2.0					■		1.6				1.5	2.2	
	IND								■							
	JPN									■						
	MEA				2.1				1.5	2.2	■			2.2	3.0	2.0
	MEX											■				
	ODA				1.6					1.7			■	1.7		
	SKO													■		
	USA									1.8					■	
	WEU														1.9	■

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 given in Table 4-11, a tanker with a capacity of 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.

Table 4-11: Tanker costs for coal and oil (/IEA 2003/)

Ship type	Size classes	Oil tanker	Coal tanker
	1000 dwt	$ million	$ 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

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*1000 km) have been assumed (/Zhao 2000/, /PGJ 2004/). Similarly for oil pipeline investment corresponding to 0.118 $/(GJ*1000 km) have been taken (/Soligo and Jaffe 1998/). The resulting transport costs for coal, oil and pipeline gas are given in Table 4-12, Table 4-13 and. Table 29.

Table 4-12: Coal trade transport costs between world regions in $/GJ (own calculations)

		Destination														
		AFR	**AUS**	**CAN**	**CHI**	**CSA**	**EEU**	**FSU**	**IND**	**JPN**	**MEA**	**MEX**	**ODA**	**SKO**	**USA**	**WEU**
Origin	**AFR**	■									0.2		0.3			0.3
	AUS		■		0.2	0.6	0.9		0.3	0.2	0.4		0.1	0.2		0.8
	CAN			■						0.2	0.6		0.3	0.2	0.5	
	CHI				■					0.1	0.3		0.1	0.0		
	CSA					■						0.1			0.1	0.2
	EEU						■									0.1
	FSU						0.6	■		0.7	0.8			0.7		0.7
	IND								■							
	JPN									■						
	MEA										■					
	MEX											■				
	ODA				0.1					0.1			■			0.5
	SKO													■		
	USA			0.5	0.73					0.6	0.5	0.1	0.7	0.7	■	0.2
	WEU															■

Table 4-13: Pipeline gas transport costs between world regions in $/GJ (own calculations)

		Destination														
		AFR	**AUS**	**CAN**	**CHI**	**CSA**	**EEU**	**FSU**	**IND**	**JPN**	**MEA**	**MEX**	**ODA**	**SKO**	**USA**	**WEU**
Origin	**AFR**															0.48
	AUS															
	CAN														0.72	
	CHI													0.25		
	CSA															
	EEU															0.19
	FSU				1.78		1.43				1.77					1.86
	IND															
	JPN															
	MEA						1.40		1.33							
	MEX															
	ODA															
	SKO															
	USA											0.48				
	WEU															

Table 4-14: Crude oil transport costs for major trade routes between world regions in $/GJ (own calculations)

		Destination														
		AFR	**AUS**	**CAN**	**CHI**	**CSA**	**EEU**	**FSU**	**IND**	**JPN**	**MEA**	**MEX**	**ODA**	**SKO**	**USA**	**WEU**
Origin	**AFR**		0.43		0.60		0.22		0.31	0.61			0.38	0.58	0.27	0.18
	AUS				0.10											
	CAN	0.66			0.22		0.49		0.50	0.17	0.56	0.27	0.32	0.19	0.18	0.44
	CHI															
	CSA	0.18			0.74		0.20		0.42	0.63		0.09	0.59	0.67	0.09	0.17
	EEU															
	FSU	0.74	0.88	0.75	0.45	0.78	0.58		0.59	0.57		0.82	0.55	0.55	0.82	0.59
	IND															
	JPN															
	MEA	0.34	0.23	0.56	0.28	0.60	0.51	0.17	0.06	0.29		0.66	0.15	0.27	0.67	0.44
	MEX														0.03	
	ODA		0.08		0.11				0.10	0.12				0.13		
	SKO															
	USA	0.27	0.63	0.18	0.60	0.09	0.24	0.82	0.52	0.51	0.67	0.03	0.73	0.55		0.21
	WEU														0.21	

4.5.2 Comparison of transport costs

The specific transport costs for different energy carriers and transport choices are displayed in Figure 4-3. 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 and hence capacities.

Oil and coal transport by tanker have the lowest specific transport costs (0.023 and 0.024 $/GJ/1000 km 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. LNG transport includes a fixed cost term due to liquefaction and regasification.

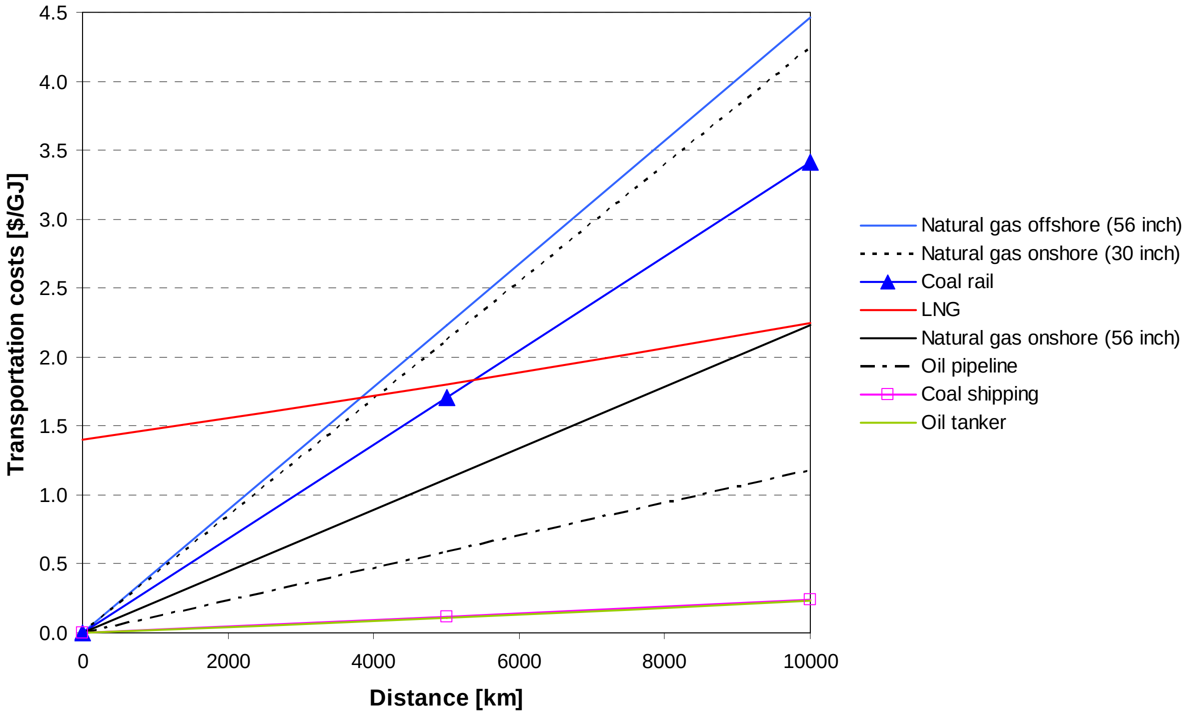

Figure 4-3: Specific transport costs for coal, oil and gas

5 Summary

In this undertaking, an overview of the supply situation for the primary energy carriers coal, natural gas, oil and uranium as well as 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 5-1. The figures for unconventional gas do not include gas hydrates, since estimations for global recoverable gas hydrate resources are highly speculative. From the fuels considered here, hard coal is the energy carrier with the by far largest quantities of reserves and resources (115,001 EJ, 1046 years of static lifetime) with large amounts in China, the FSU and the USA. Conventional amounts of oil and gas account for 14,288 EJ (88 years) and 17,174 EJ (165 years), 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, but more evenly distributed among the world regions. Since conventional natural gas resources are less scarce than conventional oil, exploration activities for unconventional gas resources have not been pursued in the same degree as for unconventional oil.

Table 5-1: Overview of reserve and resource data combined for gas, oil, coal and uranium (end of 2004 for coal, end of 2005 for conventional gas and oil, end of 2005 for uranium, end of 2002 and 2004 for unconventional oil and gas respectively[25])

Region	Gas		Oil		Coal		Uranium
	Conv.	Unconv.	Conv.	Unconv.	Hard coal	Lignite	
	[EJ]	[EJ]	[EJ]	[EJ]	[EJ]	[EJ]	1000 t
AFR	1,286	2,030	1,317	616	4,194	3	2,328
AUS	354	2,097	62	72	5,255	795	3,261
CAN	694	2,239	489	2,501	1,276	59	2,159
CHI	190	1,451	261	39	23,571	1,019	162
CSA	935	3,166	2,280	1,798	1,209	249	1,555
EEU	77	300	34	41	1,591	819	
FSU	5,342	5,465	1,283	1,033	50,007	2,105	4,834
IND	78	117	58	0	2,271	339	
JPN	5	4	1	0	3,880	38	
MEA	5,456	2,408	6,506	97	154	109	337
MEX	93	19	263	0	68	3	
ODA	706	3,086	201	22	5,344	300	1,651
SKO	0	5	0	0	2	0	
USA	1,126	2,286	956	6,046	15,839	4,148	3,414
WEU	831	950	576	214	340	913	188
Total	**17,174**	**25,624**	**14,288**	**12,479**	**115,001**	**10,900**	**20,069**
Static lifetime [a]	165	246	88	77	1046	991	298

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[25] See also footnote to Figure 3-13.

Thus, current assessments of unconventional gas deposits (total 25,624 EJ with 17,741 EJ being aquifer gas) are expected to be more uncertain.

For uranium, global conventional resources up to extraction costs of 130 $/kg U comprise ca. 11,819 kt U, which corresponds to a thermal energy of 4,425 EJ. Large amount of uranium resources can be particularly found in the Former Soviet Union, Australia, Canada, Brazil and Mongolia. Assuming current uranium consumption levels, conventional uranium resources would last for 298 years. The known uranium resources are, however, based on only limited exploration efforts so far. It is expected, that more intensive and continuous exploration on a similar level as for oil and gas may lead to higher significantly higher resources.

It is interesting to note, that unconventional oil deposits are mainly found in North and South America, which could mean, if conventional oil resources are getting exhausted, that the Western hemisphere could become an important supplier for global oil demand. This would also imply that global oil and gas trade flows, originating today mostly in the Middle East, Central Asia or Russia, might shift in the future to North and South America. Therefore, in the second part of the report the current trade patterns for the fossil energy carries coal, pipeline gas, LNG and petroleum have been analyzed. Possible future trade links have been discussed and transport costs between the different world regions have been estimated. Low specific transport costs are being observed for coal and crude oil shipping by tanker, while pipeline gas transport due to the lower energy density and LNG transport due to the liquefaction and special tankers have typically higher costs. For coal and natural gas, the transport costs can in some cases be as high or even exceed the pure extraction costs, depending on the distance. Hence, transport costs for natural gas and coal can be in the importing countries an important factor in the overall costs of energy use.

The induced price increase by producing conventional oil from fields with more difficult geological conditions (e.g. from ultra-deep sea) as well as rising production from unconventional resources, becoming economic at higher price levels, may also trigger an increased production of synthetic fuels from remote natural gas (GTL gas-to-liquids), from coal (CTL coal-to-liquid) or biomass (BTL biomass-to-liquid). At average oil price levels of 43 $\$_{2000}$/boe observed in 2005, these technologies can become already cost-effective. Assuming a coal price of 1.8 $\$_{2000}$/GJ, CTL fuels can be produced at costs of 38 $\$_{2000}$/boe /EIA 2006a/, adding CO_2 capture equipment to the plant the costs are expected to increase to 52 $\$_{2000}$/boe /AES 2006/. One necessary condition for investors to bring up the rather high upfront capital investment either for unconventional oil exploration or synthetic fuel production projects, however, is a degree of certainty or confidence that the high oil prices observed today are not a short-term market effect but will persist on a long-term base.

The example on synthetic fuels shows that the question of future availability of energy cannot be discussed isolated focusing only on the fossil or nuclear extraction sector, but requires the analysis of the entire energy system including competing options as renewable energies or technologies in the conversion and end-use sectors, e.g. increased use of electricity for heat pumps can substitute natural gas for room heating, to correctly assess the costs and benefits associated with the different production pathways. The purpose of this report and the underlying analysis is therefore to give an overview of the resource situation in terms of quantities and costs, so that this information can be used in more comprehensive analyses of the energy system, e.g. by use of energy models. Therefore, the data assumptions and calculation steps used in the resource assessment and the derivation of the transport costs have been implemented in Excel sheets, of which the structure is discussed in the Appendix.

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.

Table A-2: 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 hard 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 (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)

Table A-3: 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 (differentiation between OPEC and Non-OPEC)
2 – Unconventional	• Unconventional gas reserves and resources on a country level • Aggregation of country data to world regions (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
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

Table A-4: 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 (differentiation between OPEC and Non-OPEC)
2 – Unconventional	• Unconventional oil reserves and resources on a country level • Aggregation of country data to world regions (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
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, crude oil, 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.

Table A-5: 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)
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'

Table A-6: 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')
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

Table A-7: 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'
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

Table A-8: 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'

Table A-9: 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'
Statistics	• Statistics of crude oil trade between world regions in 2000 and 2005 • Empty 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)

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