Chapter 2
Energy

The role of oil in South Africa's energy system needs to be placed in the context of overall energy supply and demand balances, i.e. alongside other sources of primary energy and within the final energy consumption mix. Figure 2.1 displays the evolution of South Africa's primary energy supply between 1990 and 2010. None of the relative shares from the various primary energy sources have changed appreciably. Throughout the period, coal has dominated with between 72 and 77 % of primary energy. Oil's share rose notably from a low of 7.1 % in 2002 to over 14 % between 2007 and 2009 but fell back to 11 % in 2010, according to IEA data. Biomass and waste have provided between 9 and 12 % of primary energy, largely consumed by the rural population. The share of gas has remained below 3 %, while nuclear power—generated in Africa's only two reactors—provided 2.3 % in 2010. Renewable electricity, including hydropower, solar, and wind, accounts for less than half a percent of South Africa's energy supply.

Primary energy sources, including crude oil, are converted into energy carriers (e.g. petroleum fuels such as petrol, diesel, and jet fuel), which are then consumed by end users. Coal, petroleum products, electricity, and biofuels and waste have all contributed significant shares of final energy, while use of solar thermal energy remains miniscule (see Fig. 2.2). Over the period 1990–2010, the direct use of coal (i.e. excluding coal that has been transformed to electricity or liquid fuels) has shrunk from over 30 to 23 %, having made way for more efficient energy carriers such as electricity and petroleum. By 2010, petroleum accounted for the largest share of final energy consumption, namely, 30 %.

This chapter explores the implications of peak oil for South Africa's energy system. The first section examines the supply of oil and petroleum products in terms of imports, domestic production, refining and stockpiles, and analyses the demand for petroleum products according to product type and economic sector. The next section briefly considers the likely impacts of oil shocks on the energy system, while the third section presents the main options for substituting alternative energy sources for imported oil and for improving energy efficiency.

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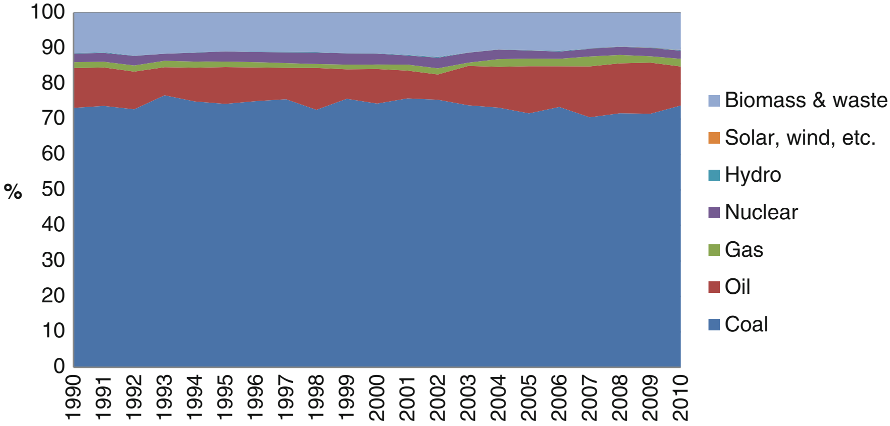

Fig. 2.1 Shares of total primary energy supply by source, 1990–2010. *Source*: IEA (2013)

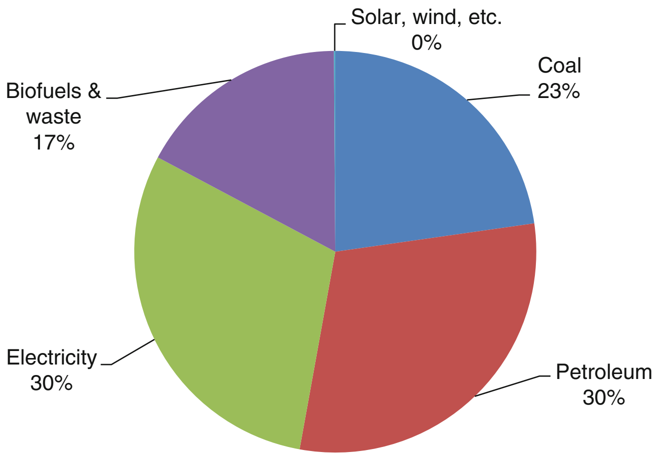

Fig. 2.2 Shares of total final energy consumption by energy carrier, 2010. *Source*: IEA (2013)

2.1 Oil Dependence of the Energy System

2.1.1 Supply of Oil

South Africa has yet to discover any significant crude oil fields. As of the end of 2012 the country's crude oil reserves stood at a meagre 15 million barrels (EIA 2013c) and were likely to be depleted within a few years in the absence of significant new oil field discoveries. The development of South Africa's petrochemical sector is something of

Table 2.1 Historical timeline of South African petroleum industry developments

Year	Development
1950	Sasol (Pty) Limited established by state-owned Industrial Development Corporation (IDC)
1954	Mobil refinery commissioned at Durban
1955	Sasol 1 commissioned at Sasolburg
1963	SAPREF refinery commissioned in Durban—joint venture between Shell and BP
1964	Creation of the Strategic Fuel Fund (SFF) to manage strategic stocks
1965	Refined fuels pipeline commissioned by South African Railways and Harbours (SAR&H) from Durban to Johannesburg via Sasolburg
1965	Soekor established by IDC and government to explore for oil and gas
1966	CALREF refinery commissioned in Cape Town—owned by Caltex (now Chevron)
1967	Crude oil pipeline commissioned by SAR&H from Durban to Johannesburg via Sasolburg
1967	Government began a project to build strategic crude oil stocks at disused coal mines at Ogies
1969	NATREF company formed between Sasol, Total, and National Iranian Oil Company (NIOC)
1971	NATREF refinery commissioned in Sasolburg
1977	UN imposed mandatory crude oil sanctions on South Africa
1977	Central Energy Fund (CEF) established, incorporating SFF
1978	Refined fuel pipeline commissioned by SAR&H from Durban to Johannesburg via Secunda
1979	Sasol purchased NIOC shares of NATREF and became the majority shareholder
1979	Sasol privatised and listed on the Johannesburg Stock Exchange
1980	Sasol 2 commissioned at Secunda
1982	Sasol 3 commissioned at Secunda
1986	Government commenced planning for a new alternative synthetic fuel plant
1989	Mobil sold its SA assets to Gencor, which formed Engen (incorporating Trek)
1992	Mossgas GTL refinery commissioned at Mossel Bay
1993	UN crude oil sanctions lifted
2001	Soekor and Mossgas consolidated to form PetroSA, as a wholly owned subsidiary of the CEF
2000s	Sasol 1 at Sasolburg converted to produce only petrochemical feedstocks
2000s	Strategic oil stockpiles at Ogies sold to Natref
2006	Sasol begins pre-feasibility studies on Mafutha CTL project at Waterberg coal field
2008	PetroSA begins feasibility studies into Mthombo oil refinery at Coega, Eastern Cape
2010	Sasol shelves Mafutha project, citing policy uncertainty regarding the Mthombo refinery and the need for carbon capture and storage
2012	Construction of a new multi-product pipeline from Durban to Johannesburg completed by state-owned Transnet Pipelines
2012	China's Sinopec Group partners with PetroSA to conduct front-end engineering design (FEED) for Project Mthombo refinery

Source: Adapted from Rustomjee et al. (2007)

an anomaly in the global context—a consequence of its lack of indigenous crude oil and a legacy from its isolation in the apartheid era (see Table 2.1 for a historical overview of major developments). After coming to power in 1948, and mindful of the fate of oil-poor Nazi Germany, the Nationalist Government was keenly aware of the critical importance of energy security—especially in light of the country's energy-intensive, mineral-dominated economy. This led in 1950 to the creation by the state of the Suid-Afrikaanse Steenkool-, Olie- en Gasmaatskappy (South African Coal, Oil and Gas Company), abbreviated "Sasol". Sasol began producing coal-to-liquid (CTL)

Fig. 2.3 Map of South Africa showing location of key energy sites. *Source*: Adapted from EIA (2013c)

synthetic fuels at Sasolburg in 1955, and, following the imposition of United Nations sanctions on the Republic in 1977, a newly privatised Sasol Limited expanded its CTL capacity to approximately 160,000 barrels per day (bpd) in the early 1980s at Secunda (in what is now Mpumalanga Province). Subsequently, the apartheid state commissioned the world's first commercial gas-to-liquid (GTL) plant at Mossel Bay on the country's southern coast (Fig. 2.3), which began production in 1993 with a capacity of 45,000 bpd. Mossgas was later merged with the state's oil exploration company, Soekor, to form the national oil company PetroSA. Today Sasol is one of the country's largest and most profitable companies, and the diverse group has interests in numerous countries around the globe, including leading GTL developments in Qatar and Nigeria. Thus as a result of its isolationist past, South Africa boasts two of the world's leading developers of synthetic petroleum products.

In 2011 South Africa is estimated to have consumed 610,000 bpd of petroleum products, of which approximately 430,000 bpd (71 %) was met by imported crude oil and refined products (EIA 2013c). The remaining domestic production of 180,000

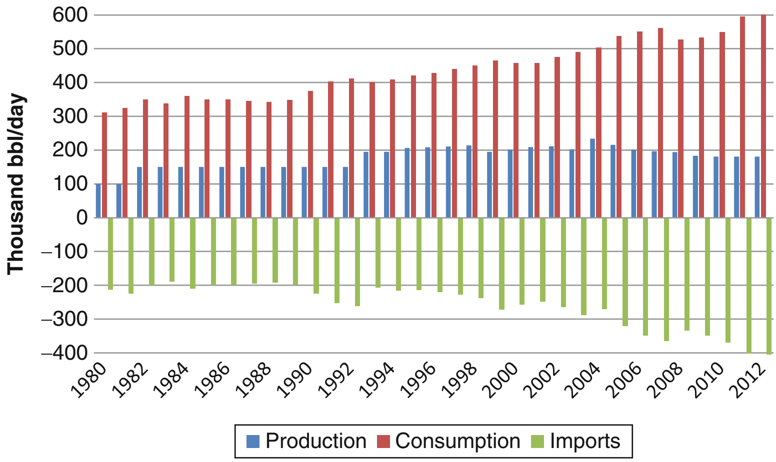

Fig. 2.4 South African oil product production, consumption, and imports, 1980–2012. *Source*: EIA (2013a)

bdp was derived from Sasol's CTL synthetic fuels (160,000 bpd or 26 % of the total) and PetroSA's production of GTL synthetic fuels (14,000 bpd) plus a very small amount of domestic crude oil and condensate (6,000 bpd), which together contributed just 3 % of total petroleum supply. Figure 2.4 displays South Africa's total annual production, consumption, and imports of oil products (crude oil plus refined petroleum products). Domestic production has remained relatively constant in a range between 180,000 and 200,000 bpd since 1993, while consumption has followed a rising trend albeit with some cyclical movements related to the rate of economic growth. Oil imports have therefore been on a gradually rising trend since 1993.

In 2011, South Africa relied mostly on OPEC nations for its oil imports, notably Iran (27 %), Saudi Arabia (27 %), Nigeria (20 %), Angola (18 %), and Oman (7 %) (see Fig. 2.5). However, reliance on Iranian crude oil imports was curtailed to a significant extent in 2012 and 2013 under pressure from the United States and the European Union, which placed sanctions on the Iranian oil industry. South Africa sourced more oil from its African neighbours and Saudi Arabia to replace the Iranian oil.

South Africa has a long history of oil refining, with the first refinery built by Mobil (currently owned by Engen) in Durban in 1954, followed by another constructed by Shell and BP (Sapref) in 1963, and a third built in Cape Town by Caltex in 1966 (now owned by Chevron). Since most of the refineries were located on the coast but a major share of fuel consumption took place in the industrial heartland surrounding Johannesburg (see Fig. 2.3), a refined fuels pipeline from Durban to Johannesburg via Sasolburg (in the Free State Province) was commissioned by the state-owned South African Railways and Harbours (SAR&H) company in 1965. This was followed 2 years later by a crude oil pipeline to feed a new inland Natref refinery at Sasolburg, which was a joint venture between Sasol, Total, and the National Iranian Oil Company (NIOC). Today South Africa has the second largest

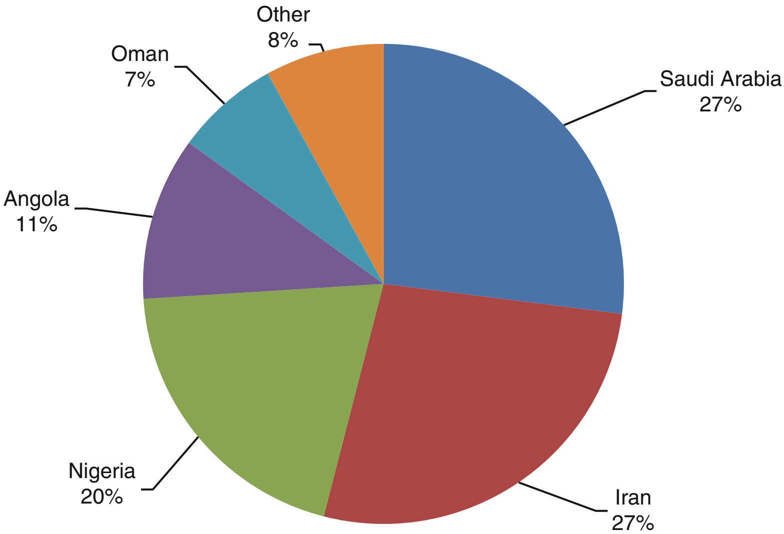

Fig. 2.5 South Africa's sources of crude oil imports, 2011. *Source*: EIA (2013c)

oil refining capacity in Africa, after Egypt. Total refining capacity in 2012 amounted to a nominal 703,000 bpd, of which 72 % comprised crude oil refining capacity with the balance of 28 % being synthetic fuel refining capacity (see Table 2.2). For many years South Africa has exported refined petroleum products to neighbouring countries in Southern Africa. From 2006 demand for refined fuels in the region (including South Africa) outstripped domestic refining capacity so that increasing amounts of refined fuels had to be imported. Petroleum fuels in South Africa are distributed from the refineries to approximately 200 depots, to 4,600 retail service stations, and directly to about 100,000 consumers, most of whom are farmers (SAPIA 2013). The existing crude oil refineries were constructed many decades ago and are due to be upgraded over the coming years to comply with cleaner fuel standards.

In the apartheid era the government created a Strategic Fuel Fund (SFF) to manage strategic oil stocks (see Table 2.1). A project was initiated in the late 1960s to convert abandoned coal mine shafts to oil storage facilities, but these stocks were sold to Natref in the early 2000s when oil prices were comparatively low. Currently South Africa maintains a strategic petroleum reserve at Saldanha Bay in the Western Cape Province. The facility has a maximum capacity of 45 million barrels, which currently translates into about 110 days' worth of oil imports (DME 2007a). Information on the actual volume of oil in storage is not publicly available. In December 2005 South African oil refineries underwent modifications in order to comply with cleaner fuel regulations, and shortages of refined product emerged in certain areas, which brought about economic losses and inconveniences. In view of this, the Department of Minerals and Energy recommended that the oil industry be required to maintain 28 days' worth of commercial petroleum product stocks (DME 2007a).

Table 2.2 Domestic crude oil and synthetic fuel refining capacity, 2012

Refinery	Barrels/day	Location	Company
Natref	108,000	Sasolburg	Sasol/Total
Sapref	180,000	Durban	BP/Shell
Enref	120,000	Durban	Engen
Chevref	100,000	Cape Town	Chevron
Total crude oil refining	508,000		
Secunda	150,000	Secunda	Sasol
Mossgas	45,000	Mossel Bay	PetroSA
Total synthetic fuel refining	195,000		
Total	703,000		

Source: SAPIA (2013)

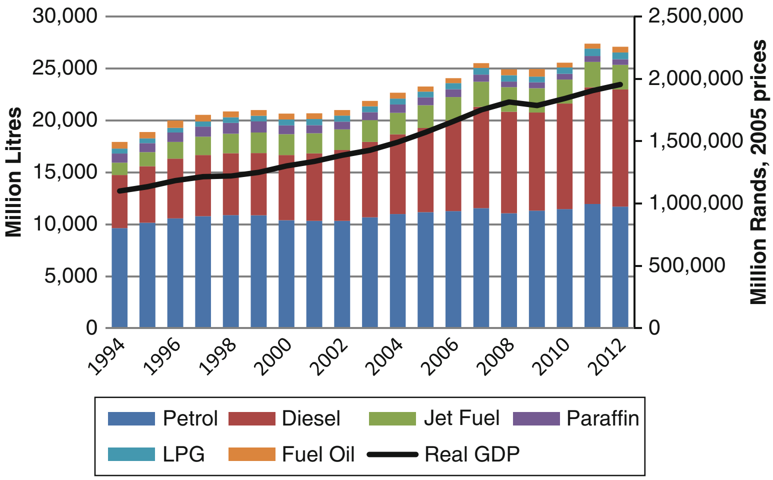

Fig. 2.6 Annual total petroleum product sales and real GDP, 1994–2012. *Source*: SAPIA (2013); SARB (2013)

2.1.2 Demand for Oil

Total annual sales of petroleum products grew largely in line with the economy (real GDP) in the period 1994–2012 (see Fig. 2.6). Petrol (gasoline) and diesel together make up more than 80 % of petroleum product sales. Liquefied petroleum gas (LPG) is used mainly for household use for cooking and heating, while paraffin (kerosene) remains an important fuel for lighting and cooking amongst poor households. The relative shares of petroleum products partly reflect demand and partly the proportions of a barrel of oil that can be refined (or "cracked") into the various products.

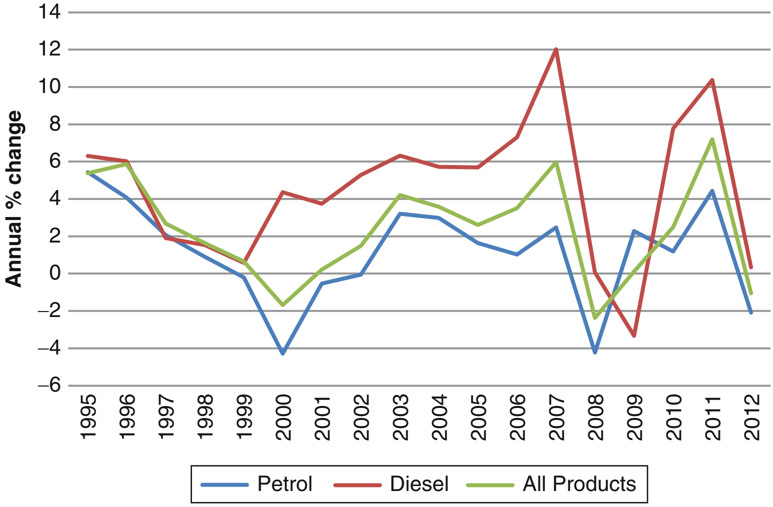

Fig. 2.7 Annual growth in petroleum product sales, 1995–2012. *Source*: SAPIA (2013)

The average growth rate for sales of all liquid petroleum fuels was 2.8 % for the period 1995–2007 (see Fig. 2.7). In that period the average annual growth rate for diesel was 5.1 % and for petrol, 1.4 %. However, these growth rates fell steeply during 2008 as a result of sharply rising fuel prices (crude oil traded at nearly $100 per barrel on average for the year) as well as tighter economic conditions, i.e. rising costs of living and higher interest rates. The recession in 2009 dampened demand for diesel (consumption fell by 3.3 %), although petrol demand grew by 2.3 % thanks to the drop in oil and petrol prices.

The transport sector accounted for the lion's share (69.8 %) of total oil product demand in 2010, while the shares consumed by other sectors were rather small: agriculture (4.4 %), industry (4.3 %), commercial and public services (3.8 %), residential (2.7 %), and non-energy uses (14.9 %) (IEA 2013). The dependence on petroleum, as measured by the shares of petroleum products in total final energy consumption, for the main economic sectors in 2010 is illustrated in Fig. 2.8. The transport sector is almost entirely dependent on petroleum (i.e. almost 98 % of the sector's total energy is derived from petroleum fuels), while agriculture relies on oil products for 59 % of its energy supply. Industry uses mainly electricity and coal and relies on petroleum for less than 4 % of its energy supply. The residential sector relies very little on petroleum for household energy use (3.4 %), while petroleum dependence is somewhat higher in the commercial and public services sector (16.3 %).

Figure 2.9 shows the per capita consumption of petroleum products for the period 1994–2012. There has been a very slightly increasing trend over the period, albeit with some undulations. Per capita demand for diesel has grown strongly and has almost caught up with that of petrol, which has been declining slightly since peaking in 1997.

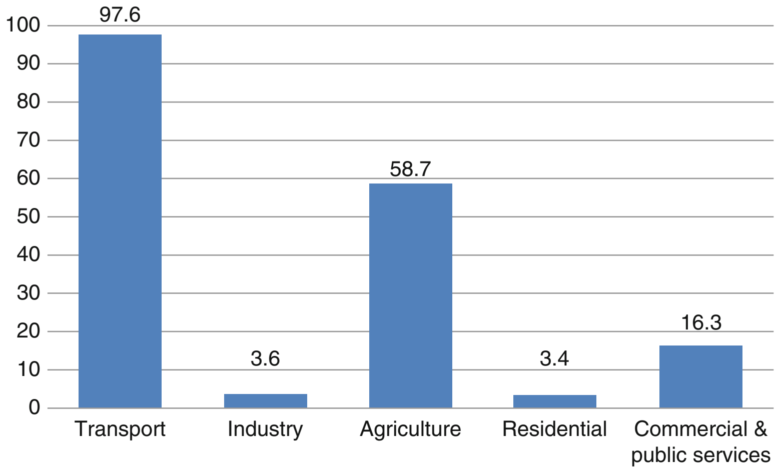

Fig. 2.8 Share of petroleum products in final energy consumption by sector, 2010. *Source*: IEA (2013)

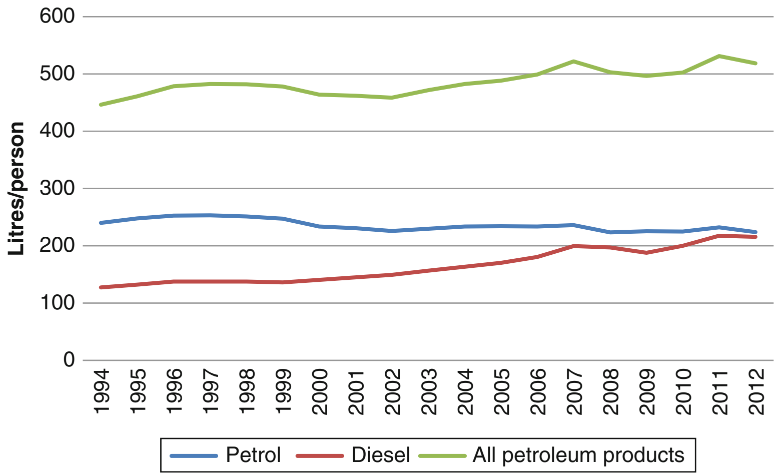

Fig. 2.9 Petroleum consumption per capita in South Africa, 1994–2012. *Source*: SAPIA (2013); StatsSA (2013)

2.2 Likely Impact of Oil Shocks

The peaking of world oil production will most likely result in a rising oil price trend, albeit with greater volatility, and the emergence at some point of physical supply shortages. Rising oil prices will gradually dampen demand and result in less petroleum energy being consumed in the country, especially in the longer term.

The prices of other energy sources, especially those that are to some extent or other substitutable for oil—such as coal and gas—are likely to rise along with the oil price. These price rises will in turn put upward pressure on the price of electricity, since coal is the feedstock for about 90 % of national power generation. Furthermore, because approximately one-third of the coal feeding state-owned utility Eskom's coal-fired power stations is transported by truck, the costs of this feedstock will rise as diesel prices rise. Higher prices of refined diesel fuel will also raise Eskom's costs of running open-cycle gas turbines (OCGTs), which are used to meet peak electricity demand (and despite their name run on diesel, not gas). The costs of buying or manufacturing, transporting, and installing alternative energy infrastructure, including wind turbines and solar panels, will also increase to some extent (all else being equal) as a result of rising petroleum fuel costs, reflecting their dependence on an economic infrastructure that is itself dependent on oil. Overall, there will be added upward pressure on electricity prices, in addition to the pressure imposed by funding requirements for Eskom's new build programme. The rising cost of fossil fuel energy will make renewable energy (RE) sources relatively more competitive and is likely to stimulate investment in this sector. Increased production of RE technologies could deliver economies of scale and learning and hence reduce their prices, setting off a positive feedback loop. Thus over the longer term, one can expect a process of (partial) substitution of renewable energy for oil and coal. If economic conditions are deteriorating (as discussed in Chap. 5), however, the expansion of RE might not be rapid enough to offset declining consumption of fossil fuels, resulting in diminishing total energy consumption. In addition most alternative energy options are not direct substitutes for liquid petroleum fuels.

Acute physical shortages of oil products, which could arise from time to time owing to global supply interruptions, could have even more serious consequences than gradually rising (or volatile) energy costs. Most immediately, Eskom's demand for diesel fuel to run its OCGT peaking power plants will have to compete with transport, agriculture, and other demand sectors for scarce diesel supplies. Perhaps most significantly, a sudden interruption of liquid fuel supplies could disrupt the flow of coal to power stations and thereby seriously compromise Eskom's ability to maintain sufficient power generation to keep the national electricity grid stable. Although not caused by liquid fuel shortages, a similar situation arose in early 2008 when problems in the procurement and transportation of coal resulted in insufficient stockpiles at some power stations, contributing to the electricity crisis which involved extensive blackouts and load shedding. Power outages would in turn hamper the refining of petroleum fuels and their distribution through pipelines and at retail outlets, thus setting in motion a self-reinforcing feedback loop with very adverse consequences.

2.3 Weaning Off Oil: Energy Substitutes and Conservation

In terms of mitigating the impacts of global oil depletion, the primary goal for the energy sector is to reduce reliance on imported oil. This should involve a combination of curtailment of demand for oil products and a shift to more sustainable energy sources. The government's main approach to liquid fuel supply is summarised in the *Energy Security Master Plan—Liquid Fuels* (DME 2007a). This document recommended a set of mostly infrastructural short- to medium-term strategies and longer term strategies which essentially amounted to the development of modelling capacity and policy formulation. Specific recommendations made by the Department of Minerals and Energy included the procurement by PetroSA of 30 % of South Africa's crude oil supply, apparently in order to reduce the risks of reliance on a few sources of oil imports; the promotion of local liquid fuel production; mandating energy companies to ensure adequate commercial fuel inventories; and the cross-sectoral promotion of energy efficiency, noting in particular the risks of over-reliance on oil by the transport sector.

The infrastructural strategies emphasised the need for adequate quantities of refined fuels to be made available to meet rising demand, especially in the economic heartland of Gauteng Province. In view of this, two major petroleum infrastructure projects were initiated. The first is Transnet Pipeline's new multi-product fuel pipeline connecting the port city of Durban with the inland Gauteng Province, which was commissioned early in 2012. The second is PetroSA's proposal for a new oil refinery, dubbed "Project Mthombo", to be located at the port of Coega near the city of Port Elizabeth in the Eastern Cape Province (see map in Fig. 2.3). Mthombo was originally slated to have a capacity of 400,000 bdp, which would make it the largest refinery in Africa, and early projections put the cost at around $11 billion (approximately R110 billion). PetroSA is partnering with Chinese firm Sinopec to investigate the front-end engineering and design for the refinery. As of this writing, however, the government has yet to approve the project.

Both the new pipeline and the proposed refinery assume that increasing quantities of crude oil will be available globally and affordable over their lifespans (of at least 50 years). Like the *Liquid Fuels Master Plan,* these projects take no account of the future limitations on crude oil imports that will be imposed sooner or later by declining world oil exports and rising oil prices. To address this vital policy deficiency, this section explores the alternative sources of energy supply that could substitute for imported crude oil and refined petroleum fuels. I also discuss demand-side management, in terms of energy efficiency and conservation initiatives, and motivate for South Africa to sign an international Oil Depletion Protocol to guide a co-ordinated reduction in oil consumption.

2.3.1 Developing Domestic Energy Alternatives

South Africa's state-owned oil company PetroSA produces approximately 1,800 bpd of crude oil from its Oribi and Oryx fields off the southern tip of the country, about 0.3 % of the nation's oil use (PetroSA 2012). Although oil exploration is continuing off the western and southern coasts, no new oil discoveries have been announced as of this writing (November 2013), and therefore there is no expectation of a notable increase in domestic crude production in the foreseeable future. Hence, the realistic prospects for domestic liquid fuel production rest on CTL, GTL, and biofuels, which are considered in turn below. Aside from these sources, biogas can potentially substitute for liquefied petroleum gas, while electricity represents a general—although imperfect—energy replacement for petroleum fuels.

2.3.1.1 Coal to Liquids

Sasol currently supplies approximately 26 % of South Africa's annual liquid fuel demand from its CTL plant at Secunda in Mpumalanga Province (see map in Fig. 2.3). The major advantage of CTL is that it is a reliable technology with a proven track record, which produces synthetic petroleum fuels (synfuels), including petrol, diesel, and jet fuel, that are usable in existing transport infrastructure. Expanding domestic CTL production would therefore reduce South Africa's dependency on oil imports and save foreign exchange. Although information on Sasol's CTL production costs is not publically available, it may be assumed based on the company's profitability that they are less than the cost of refined fuel imports. In March 2010 Sasol's board approved the first phase of a project to expand the synfuels and electricity generation capacity of the Secunda plant by approximately 3.2 %, using natural gas imported from Mozambique as feedstock (Sasol 2010). The Secunda expansion is due to come on stream in 2014.

Sasol has also investigated the viability of a new CTL plant to be located at the Waterberg coal field in Limpopo Province (Sasol 2010: 20) (see map in Fig. 2.3). Named Project Mafutha, the proposed plant had a capacity of 80,000 barrels of liquid fuels per day, about half of Sasol's existing synfuel production volume. Sasol has indicated that it would not be the sole investor in such a large-scale project, which was estimated to cost in the region of R160 billion (around $16 billion), and the company sought financial support from government (Njobeni 2010). In 2008 Sasol signed a Memorandum of Understanding with the Industrial Development Corporation for a planned investment in the project, and the company also held investment talks with the departments of Trade and Industry and Minerals and Energy. According to Sasol, Project Mafutha would likely take up to 10 years to complete. If both Project Mafutha and the Secunda extension materialised, Sasol's synfuels would meet about 40 % of the country's 2010 liquid fuel demand.

Construction of a new CTL plant faces several risks and would entail costs other than purely financial costs. First, such a project would be viable only if sufficient coal feedstock could be secured for the lifetime of the project. While the Waterberg coal field is relatively underutilised, South Africa's remaining coal reserves are the subject of much contention. The official government figure for reserves was revised downward greatly from over 50 gigatonnes (Gt) to under 30 Gt in 2007 (GCIS 2007). However, recent research casts doubt on even this latter figure. Professor David Rutledge estimates that remaining recoverable coal reserves in Southern Africa (the vast majority of which are in South Africa) may be as low as 10 Gt (Rutledge 2011). Based on historical production data and the "Hubbert linearisation" method, local geologist Chris Hartnady forecasts a peak in domestic coal production at about 284 million tonnes per annum (mtpa) in 2020, up slightly from the 2012 level of production of 260 million tonnes (Hartnady 2010). On the other hand, Eskom's demand for coal for electricity generation is set to rise by approximately 30 mtpa (to feed its new Medupi and Kusile power plants) to a peak of around 155 mtpa in 2021, thereafter declining as old power plants are decommissioned (Eberhard 2011). Meanwhile, the coal industry has plans to increase exports from about 65 mt in 2010 to over 90 mt by 2020. The proposed Mafutha CTL plant would require approximately 25 million tonnes of additional coal per annum. If the conservative coal production forecasts noted above turn out to be accurate, then coal production in the country as a whole will not be able to rise sufficiently to meet projected growth in demand by Eskom, other domestic users, exports, and a new CTL plant. Trade-offs amongst these competing uses of coal would have to be made at some point, and domestic coal prices would likely rise considerably. Under these circumstances, it might make more sense for the Waterberg coal to be used to maintain electricity production from existing power plants rather than to feed a costly new CTL plant. Some of this electricity could be used to power transportation (e.g. electric trains and road vehicles), as discussed in the next chapter.

The second risk to building a new CTL plant is that, even if sufficient feedstock were procured, the energy return on investment (EROI) for CTL could be rather low. While the energy content of a tonne of coal (22.75 mBtu) is more than four times the energy contained in a barrel of oil (5.45 mBtu), the CTL process produces between 1 and 1.4 barrels of synfuel per tonne of coal (Höök and Aleklett 2010). This demonstrates that there is a significant "energy price" to pay for converting coal into liquid fuels, which is compensated by the higher prices attracted by liquid fuels on the market due to their convenience. While there are no estimates for the EROI of coal or CTL in South Africa, international estimates for the EROI of coal range from between 60:1 and 80:1 in the United States to around 21:1 in China (Lambert et al. 2012). The EROI for coal mining can be expected to decline over the long term as the quality of ore grade diminishes, hence raising production costs. An experienced local geologist has also raised questions about the quality and accessibility of the Waterberg coal deposits (Hartnady 2010).

A third risk to expansion of CTL capacity is posed by the potentially high environmental costs in the form of water and air pollution, including additional greenhouse gas (GHG) emissions, which contribute to climate change. In view of South Africa's climate mitigation commitments under the Copenhagen Accord of 2009, Sasol may be required to install carbon capture and storage (CCS) technology at a new CTL plant, which would raise its costs considerably. Costs of CTL fuels would also rise following the announcement by the Minister of Finance in February 2013 that a carbon tax would be phased in from 2015. In addition, CTL facilities require large quantities of water, which is an increasingly scarce resource in Southern Africa in general and in the Waterberg area in particular (Hartnady 2010). Finally, the pollution resulting from coal mining and combustion can also have negative impacts on human health, such as respiratory diseases (Spalding-Fecher and Matibe 2003).

In view of these risks, and also because of the unaffordability of the projected financial costs, Sasol put Project Mafutha on hold in late 2010. Given the substantial lead times required for new investments of this scale, it is probably safe to assume that no new CTL plant will be built in South Africa for the remainder of this decade at least.

2.3.1.2 Gas to Liquids

PetroSA produces liquid fuels using natural gas feedstock at its GTL refinery at Mossel Bay on the southern coast (see map in Fig. 2.3). Maximum production capacity is 45,000 bpd of synfuels, although in recent years actual production has been curtailed to less than half of this amount, owing to maintenance issues and gas feedstock supply constraints (PetroSA 2012). The existing gas fields in the Bredasdorp basin, including the newly authorised F-O field (dubbed Project *Ikwhezi)*, are expected to last until at least 2018. The company states, “Further development of other gas prospects near the F-O field could potentially help to sustain the life of the Mossel Bay refinery until 2025”. PetroSA is also conducting exploration activities off the country’s west coast but as of this writing had not announced any discoveries.

There are at least three other potential sources of natural gas that could supply feedstock to the Mossel Bay GTL refinery or possibly even a new GTL plant (which could be built by either Sasol or PetroSA): imported gas, shale gas, and underground coal gasification. In recent years there have been very substantial discoveries of conventional natural gas offshore of Namibia and Mozambique, which led the Department of Energy and PetroSA to explore the feasibility of importing liquefied natural gas (LNG). LNG has to be transported in special tanker ships and then regasified before it can be used onshore, which requires costly new infrastructure. In 2010 PetroSA’s management decided against the LNG option and chose the local development project *Ikwhezi* instead (PetroSA 2010). However in July 2013 PetroSA announced that it was planning to build a floating LNG terminal near its Mossel Bay refinery and appointed an Australian company to conduct a front-end engineering design study with a view to making a final investment decision in late 2014 (Burkhardt 2013). Although LNG prices have in the past been quite closely correlated to oil prices, the development of shale gas in North America over the past few years has lowered gas prices in that region and also softened world LNG prices. However if South Africa does pursue the LNG option, it will have to compete on the global LNG market with the likes of China, Japan, India, and South Korea.

Another potential source of feedstock for GTL plants, albeit highly contentious, is shale gas. In April 2011 the South African Cabinet placed a moratorium on shale gas exploration and appointed an interdepartmental task team to investigate the economic, social, and environmental implications of shale gas development. The Working Group on Hydraulic Fracturing delivered its report in July 2012 (DMR 2012), and the report was subsequently endorsed by the Cabinet. A study commissioned for the US Energy Information Administration (EIA 2011) indicated that South Africa may have potential for shale gas deposits in the Karoo Basin (which underlies a large central portion of the country) amounting to 485 trillion cubic feet (Tcf) of technically recoverable resources. This estimate was reduced to 390 Tcf in a follow-up report (EIA 2013b). However, the Working Group stated that “owing to the limited amount of available data in the area, it is impossible to quantify the resource accurately, other than to say that it is potentially very large”. Experience from the United States and other countries suggests that the commercially viable portion of shale gas resources is likely to be much smaller than the technically recoverable resource (Berman 2010; Hughes 2011; Hughes 2013). Furthermore, serious concerns have been raised about potentially negative social and environmental side effects related to the contamination of water and air pollution (Howarth et al. 2011; Hughes 2011). Of particular concern is the limited availability of and possible contamination of freshwater, which is a very scarce resource in the Karoo area.

In September 2012 the Cabinet endorsed the lifting of the 18-month moratorium on shale gas exploration upon the recommendations of the task team. However, only "normal" exploration methods, and not hydraulic fracturing, would be allowed for an initial 6–12-month period while the regulatory framework was augmented. The companies that have been awarded exploration licences still have to complete Environmental Impact Assessments before any exploratory drilling can take place. According to the Working Group report (DMR 2012: 29), "It may take 10 or more years for a successful project to progress from the issuing of an exploration right, through the drilling of a discovery well, the drilling of a number of appraisal wells, the development of an economic feasibility plan, the application for and issuing of a production right, the drilling of production wells and the installation of the pipeline infrastructure before gas is delivered to the end user". As of this writing, therefore, the potential of shale gas to contribute to the energy supply in South Africa remains uncertain, and it seems unlikely to play a meaningful role this decade but could potentially have a major impact on domestic energy markets after 2020. If a commercially recoverable resource of, say, 30 Tcf were established, this could potentially sustain PetroSA's current operations and possibly provide feedstock for new GTL production.

A third source of feedstock for GTL could potentially come from a process called underground coal gasification (UCG), a process whereby coal is ignited in situ underground, fed through a borehole by air or oxygen to yield a synthetic gas (syngas). The syngas can be used for electricity generation, for the production of synthetic liquid fuels or for industrial uses. In addition to this flexibility, several other advantages are claimed for UCG (Eskom 2010; Shafirovich and Varma 2009). First, otherwise uneconomical resources can be utilised; Eskom estimates that an additional 45 billion tons of coal could be exploited through UCG, over and above existing proved reserves. Second, capital investment costs are lower than for conventional coal plants. Third, there are no costs incurred for transporting coal. Fourth, there is no need for traditional mining, and therefore associated health and safety risks for miners are reduced. Fifth, indications from a pilot UCG project in Australia indicate that the process has a much lower environmental impact (in terms of groundwater contamination, land degradation and subsidence, and greenhouse gas emissions) when compared to conventional coal mining. Eskom has a small pilot UCG plant in operation at its Majuba power station in Mpumalanga and began commercial co-firing of gas and coal in October 2010. Eskom is optimistic that the costs will compare favourably with those of conventional coal mining and power generation.

Nonetheless, there are several disadvantages and risks attached to UCG. First, although UCG might produce a smaller volume of GHGs per unit of energy than conventional coal, there are still considerable emissions to deal with. Second, there are concerns about possible underground water contamination and land subsidence (Shafirovich and Varma 2009). UCG has yet to be proven on a commercial scale and thus is a highly uncertain potential contributor to gas supplies in SA. In any event, since the coal fields are located in the northern areas of the country while PetroSA's GTL refinery is in the southern Cape, costly pipeline infrastructure or a new GTL plant would be required to convert coal gas into liquid fuels.

In conclusion, it is reasonably assured that PetroSA will continue to produce GTL from its Mossel Bay refinery until at least 2018 using gas from the southern Cape offshore fields. Beyond that, there are various possibilities for expanding GTL production from domestically produced gas (if new conventional fields are found or if shale gas is found and developed) or from imported gas. However, each of these options would require costly infrastructure investments and could have seriously detrimental environmental side effects.

2.3.1.3 Biofuels

In December 2007 the South African Government approved a *Biofuels Industrial Strategy* (DME 2007b). Citing food security concerns, the Strategy excluded maize as a feedstock for ethanol, advocating instead grain sorghum, sugar cane, and sugar beet. The Strategy also proposed that biodiesel be produced from soya beans, canola, and sunflower oil. The target for biofuel penetration was set as 2 % of liquid road fuels by 2013, in an initial 5-year pilot phase. In August 2012 the Department of Energy gazetted regulations pertaining to the Mandatory Blending of Biofuel with Petrol and Diesel in South Africa, although the implementation date is still to be determined by the Minister of Energy. The regulations stipulate that bioethanol must comprise between 2 and 10 % of petrol on a volumetric basis, while diesel should have a minimum concentration of 5 % of biodiesel volumes.

Obstacles to the development of biofuels in South Africa thus far have included the following factors: low levels of awareness about the opportunities inherent in biofuels; technical challenges; food insecurity concerns; water scarcity; difficulties accessing financing; human capacity constraints; and an uncertain policy and regulatory environment (Amigun et al. 2008; Chakauya et al. 2009). Although large-scale production of biofuels may now become viable under the new regulations, the constraints imposed by water and arable land scarcity suggest that it is unlikely that biofuels will make a significant contribution to national liquid fuel supplies beyond what is envisaged in the blending regulations, i.e. approximately 5 % of current liquid fuel demand (about 30,000 bpd). Perhaps more importantly, the real contribution of biofuels will in all likelihood be severely limited by low EROI ratios, which have been estimated at averaging around 0.9:1 for biodiesel and 1.3:1 for ethanol (Lambert et al. 2012).

For the longer term, there may be the possibility for the so-called second-generation biofuels, such as cellulosic ethanol, which utilises non-food crops, agricultural waste, and wood chips as feedstock (Woodson and Jablonowski 2008), and biodiesel produced from algae (Rhodes 2009). The main problem with cellulosic ethanol is that cellulose is much, much harder to break down than starch, which lowers the net energy yielded by the conversion process. Furthermore, there is no ecological "free lunch": for arable land to remain fertile, a significant proportion of the nutrients contained in the biomass must be returned to the soil—the more so when synthetic fertilisers become relatively scarcer and more costly. The purported benefits of microalgae are rapid growth rates, high oil content, and high yields and the fact that it can be grown using saline water or wastewater. But despite hundreds of millions of dollars being spent on research over the past decade, no significant volumes have been produced to date and costs are very high (Hall and Benemann 2011). Commercialisation of microalgae will require improved algae strains and innovations that lower harvesting and oil-extraction costs and boost co-product output. Thus second-generation biofuel technologies are still in the research and development stage, and it will likely take a decade or more before they can be successfully commercialised.

2.3.1.4 Biogas

Biogas, which is generated from the anaerobic fermentation of organic material, is a substitute for LPG. It has several advantages: (1) it can be produced from organic waste matter and therefore control pollution, including GHG emissions; (2) useful by-products include fertiliser and water; (3) production technology is simple and efficient at both large and small scales, in rural and urban settings; (4) it alleviates pressure on wood resources, deforestation, and related environmental impacts; and (5) biogas systems can be constructed and operated locally (Amigun et al. 2008: 701–2). Capital costs represent the largest component of biogas costs, while operation and maintenance costs are relatively low and the feedstock is often free as it consists of various waste materials. The biogas can be used for heating and cooking, or it can be converted into electricity.

Nevertheless, biogas does have several drawbacks, such as the energy losses that occur in the conversion from biomass to gas and then to heat or power, and the need for the digester to be warm or insulated. More importantly, biogas is a diffuse energy source relative to fossil fuels, which means that if production is to occur at a significant scale then feedstock will have to be transported long distances. It has been estimated in the South African context that transport costs are the second largest component of biogas manufacturing costs, and therefore decentralised plant location close to feedstock sources (and final consumption) is important (Nolte 2007). Biogas therefore presents a good opportunity for sustainable energy supply but on a relatively small, local scale. It has been estimated that 300,000 (mainly rural) households could utilise biogas digesters in South Africa (Trollip and Marquard 2010).

2.3.1.5 Electricity

Electricity can in principle replace petroleum-based transport fuels, although this would require a costly and time-consuming replacement of the current petroleum-based vehicle fleet with electrified transport infrastructure (various options for which are discussed in Chap. 3). Electricity can also substitute for paraffin (which is used chiefly by low-income households for lighting and cooking) and LPG (also used for cooking). However, these new uses of electricity would need to compete with other demand sectors such as industry, commerce, agriculture, and residential. By 2007–2008, demand for electricity had already outstripped Eskom's supply capacity, resulting in a near-collapse of the grid and subsequent power rationing and demand restrictions. Eskom has warned that its generation capacity will be severely constrained until at least 2017, when the first unit of the second new base-load coal-fired power station (Kusile) is due to be commissioned (DoE 2011).

In 2011 the South African Department of Energy published an "Integrated Electricity Resource Plan for South Africa—2010 to 2030" (IRP2010), which projected future electricity demand on the basis of an assumed economic growth rate of 4.6 % per annum and spelled out how generating capacity would increase to meet this demand (DoE 2011). Of the 45 gigawatts (GW) of new capacity envisaged in the IRP2010, 42 % is renewables, 23 % nuclear, and 15 % coal (which excludes 10.1 GW of new coal-fired capacity that was already "committed"). However, the share of electricity actually *generated* from renewable sources was forecast to be just 9 % in 2030 (excluding 5 % for hydro), as a result of the lower load factors for solar and wind power compared to other sources. The IRP2010 also includes 7.3 GW of capacity from OCGTs, fed by diesel. Interestingly, the Department of Energy partially justifies its decision to build 9.6 GW of new nuclear generation capacity on the basis that it "should provide acceptable assurance of security of supply in the event of a peak oil-type increase in fuel prices", which would likely make operation of the OCGTs prohibitively expensive (DoE 2011: 14). As of August 2013, however, the government had not yet given the green light for the nuclear build programme, as it investigated the massive costs and the possibility of tapping natural gas from Namibia and Mozambique instead. Even if the new nuclear build programme does proceed, it will not produce power before about 2024 at the earliest. If exploration for shale gas in the Karoo Basin yields substantial commercial reserves, this could be a potential game changer in the power sector—although again not before the early 2020s and with potentially serious environmental and health consequences.

The Department of Energy's projections for electricity demand growth are probably over-optimistic in light of sluggish economic growth in an adverse global environment, together with the doubling of electricity tariffs that occurred between 2008 and 2013 and the recent decision by the regulator to allow further increases of 8 % a year for the next 5 years. On the other hand, the IRP2010 does not advocate replacing liquid fuels with electricity for transport (the case for which is presented in Chap. 3). The country's further development is therefore likely to require substantial increases in power capacity. Leaving gas aside, the future arguably lies in renewable energy sources. South Africa is a water-scarce country and has largely exploited its large-scale hydropower potential, while biomass cogeneration and landfill waste will make relatively small contributions to the power mix in the foreseeable future.

The best prospects for renewable electricity probably lie in South Africa's abundant solar resources, estimated to be amongst the best in the world (Pegels 2010). The national nominal potential for concentrated solar power using existing, proven technology has been estimated as 548 GW, with an effective capacity of 212 GW, which is about five times the country's total electricity generation capacity in 2012—although the technology would have to overcome water scarcity (Fluri 2009). However, recent research has suggested that the energy return on investment for solar photovoltaic power could be in the range of 6–12:1, about half that for coal-fired electricity (Raugei and Fthenakis 2012), and even lower at 2.4:1 in Spain (Prieto and Hall 2013). Wind energy resources are less abundant than solar in South Africa, but the average EROI for wind power in international studies is about 18:1 (Lambert et al. 2012). The South African Wind Energy Association (SAWEA) has estimated that 30 GW of wind power capacity could be installed by private operators by 2025, displacing some 6 GW of conventional base load power, assuming a conservative capacity factor of 0.2 (SAWEA 2010). Although ocean power technology is still in its infancy, wave power potential on the extensive coastline of South Africa has been estimated at between 8,000 and 10,000 MW (Holm et al. 2008).

Although the current financial costs of renewable technologies are mostly fairly high compared to existing conventional power generation, the cost trend for coal- and oil-fired electricity is upwards (as the resources deplete), while the cost trend for renewable energy is largely downward as the technologies improve and increased production yields economies of scale. This is evidenced by the appetite of private sector players, who have initiated solar and wind power projects totalling over 3 GW after the first two successful rounds of bidding under the DoE's Renewable Energy Independent Power Producer Procurement Programme took place in 2012. However, another important factor that needs to be considered in both net energy and economic calculations is that increasing the reliance on intermittent energy sources like solar and wind will require investment in back-up generation and/or storage capacity as well as extensions and upgrades of the national grid. Much more detailed investigation is required before we can adequately evaluate the potential of renewable energy vis-à-vis fossil fuels.

2.3.1.6 Liquid Fuel Scenarios

It is instructive to create scenarios for future liquid fuel supplies in South Africa, based on assumptions and evidence discussed above. As shown in the introduction, several analysts expect world oil production to begin declining within a few years, possibly at a rate of 2–5 % per annum (Hirsch 2008). Furthermore, world oil exports have been stagnant since 2005, and an increasing proportion of these are being consumed each year by China and India (Brown 2013). Thus a conservative assumption is that world oil exports could decline by about 5 % p.a. once global oil production begins to decline, which is assumed here to be in 2015 for illustrative purposes. The simplest assumption for South Africa's oil imports is that they will decline at a similar rate as world oil exports, which assumes that South Africa maintains its share of

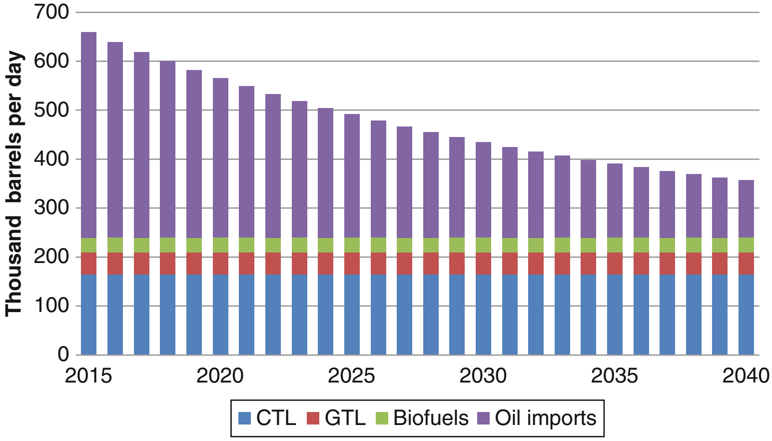

Fig. 2.10 Baseline liquid fuel scenario with 5 % oil import decline rate. *Source*: Author's calculations

world oil consumption, which was about 1 % in 2011. If anything, this is an optimistic assumption, as larger and richer nations are more likely to be able to out-bid South Africans for declining supplies of oil. For domestic synthetic fuel supply, it is assumed for this scenario that Sasol increases its 2012 level of production by 3.2 % in 2014 (to 165 kbpd) as per its stated plans (Sasol 2010) and maintains this level until 2040, assuming that its Secunda facilities commissioned in the early 1980s have an expected lifespan of up to 60 years. Furthermore, it is assumed that PetroSA produces at full capacity (45 kbpd) for 8 years, sustained by the newly found F-O gas field (PetroSA 2010), after which it sources feedstock either from domestic shale gas or from imported LNG. The contribution of biofuels is assumed to be limited to that mandated in the Biofuels Industrial Strategy, namely, 5 % of 2013 road fuels (30 kbdp). Finally, it is assumed that net oil imports rise slightly to 420 kbpd in 2015. Assuming a 5 % decline in oil imports beginning after 2015, the relative contributions of imports and domestic fuel supplies are shown in Fig. 2.10. Total liquid fuel supply would be 74 % of its 2015 level by 2025 and 54 % of its 2015 level by 2040. Should the onset of global oil production decline occur sooner or later than 2015, the depletion profiles would simply be shifted earlier or later by the corresponding number of years.

2.3.1.7 Capital Costs of Alternative Liquid Fuels

Estimated capital costs for various liquid fuel alternatives are listed in Table 2.3. It is clear that CTL and GTL plants are much more expensive than ethanol and biodiesel plants, both in absolute terms and per litre of fuel production capacity. Small-scale biodiesel plants have the lowest cost per litre of daily production. Feedstock costs for all types of plant are highly variable and can be expected to increase over time—as a result of depletion in the case of coal and gas and due to land, water, and food shortages in the case of biofuel crops.

Table 2.3 Comparison of liquid fuel capital costs for some proposed projects

Fuel type	Capital cost	Capacity	Unit capital cost	Source
	R million	litres/day	R/litre/day	
CTL	160,000[a]	12,720,000	12,579	Donnelly (2010)
GTL	74,000[b]	5,247,000	11,206	Engineering News (2011)
Ethanol	2,000[c]	548,000	3,448	Roelf (2012)
Biodiesel	0.085	600	142	Biodiesel Centre (2011)
	0.325	3,000	108	Biodiesel Centre (2011)
	0.025	113	221	NanoElf Biodiesel (2011)
	0.036	200	182	NanoElf Biodiesel (2011)
	164[d]	61,644	2,663	Nolte (2007)

Notes:
[a]Sasol's proposed Mafutha project for the Waterberg area in Limpopo Province, South Africa
[b]Chevron and Sasol's joint-venture GTL plant in Nigeria. Capital costs were converted from US$ to Rands using an exchange rate of R8.8/$ (March 2013)
[c]Proposed ethanol plant to be constructed in the Eastern Cape Province by 2014, as part of the government's biofuels programme
[d]Capital costs cited (Nolte 2007) were for the year 2006; these values were updated to 2011 by using the GDP deflator, which increased them by a factor of 1.37

2.3.2 *Energy Conservation and Efficiency*

Given the limitations on alternative energy supplies, energy conservation and efficiency are essential to combat the future decline in oil availability and affordability. Since all energy sources are substitutes to some degree—at least in the long run—a national programme to promote conservation and efficiency should apply to all energy sources. The most important area for oil conservation is transport, given that this sector consumes three-quarters of oil products in South Africa; measures to boost efficiency and curtailment of oil use in transport will be discussed in Chap. 3. Consumption of petrochemical products such as plastics can be reduced through improved recycling programmes. The need for bitumen will be reduced to an extent as road-based transport is shifted to railways, alleviating the maintenance pressure on roads (see Chap. 3), although this will come at the cost of coal needed to manufacture steel railways. Efficiency improvements should be implemented at the point of energy generation (e.g. upgrading oil refineries and power plants to be as efficient as possible) as well as distribution (e.g. rationalising the logistics of fuel transport and/or using pipelines rather than trucks to carry fuel). Efficiency measures in the electricity sector could include the adoption of more efficient technologies (e.g. integrated supercritical coal power plants), implementation of smart grids, decentralisation of electricity generation to reduce distribution losses, installation of solar water heaters, and cogeneration of heat and power (Greenpeace 2011; Winkler et al. 2010).

A national drive for energy efficiency and conservation could be led by central government and encouraged by a combination of awareness campaigns, statutory regulations (e.g. mandatory efficiency standards), and economic incentives (e.g. tax rebates for efficiency). Fortunately, several years of electricity supply constraints and rising tariffs have begun to change consumer behaviour, which was wasteful after decades of very cheap power. The "rebound effect"—the tendency of consumers to spend the money saved through energy efficiency gains on other goods and services that embody or use energy—is unlikely to be a major problem given the expected increases in prices for electricity and liquid fuels. The efficiency programme would benefit from explicit national targets for oil demand reduction, similar to the efficiency targets adopted by the Chinese Government (see the further discussion in Chap. 7).

2.3.3 *Oil Depletion Protocol*

Colin Campbell and Richard Heinberg have suggested an Oil Depletion Protocol as a cooperative response to declining oil supplies (Campbell 2006; Heinberg 2006a). The Protocol in essence requires all oil-importing nations to agree to reduce their annual oil imports by a percentage equal to the World Oil Depletion Rate, which has been estimated by Campbell as approximately 2.6 % per annum. In addition, oil-producing nations would agree to reduce their rate of production by their National Depletion Rate. The result will effectively be a global rationing system, which is intended to help stabilise oil prices and avoid wars over remaining oil and thereby ensure that economic and social conditions are more conducive to the crash programme of mitigation required to avoid the worst potential economic impacts. Heinberg suggests that the Oil Depletion Protocol could operate alongside carbon emission-based agreements such as a strengthened and extended Kyoto Protocol.

While the Oil Depletion Protocol has merits in theory, it would face similar obstacles to international adoption and implementation as have confounded climate treaty negotiations. In particular, there are likely to be conflicts between various groupings of countries, such as between developed and developing nations (the latter may argue that they have a right to a greater proportion of remaining oil reserves to compensate for their lower historical oil consumption) and between oil-importing and oil-exporting nations. The situation resembles a complex version of the prisoner's dilemma, in that the individually rational country strategies are likely to lead to a socially suboptimal outcome. The Protocol represents a mutually cooperative set of strategies that would be very difficult to achieve in practice but would yield benefits for most countries.

2.4 Conclusion

All of the potential substitutes for imported oil have both advantages and limitations. The main advantage of CTL and GTL technologies is that they produce fuels that can be used in existing transport infrastructure. The disadvantages include a depleting resource base, probably relatively low EROI, high capital costs, water scarcity, and pollution (including GHGs). Biogas has potential as a sustainable, local replacement for LPG and wood fuel. Liquid biofuels (ethanol and biodiesel) might make a small contribution to liquid fuel needs but will be severely constrained by scarcity of water and high-quality arable land and may undermine food security. The best prospects for biofuels are probably for small-scale, decentralised biodiesel production, especially for use on farms. Electricity is a flexible energy carrier that can be used for multiple purposes including transport, although new generation, transmission, and distribution infrastructure will need to be constructed. Nuclear energy provides a relatively reliable base-load power source but faces very high capital investment and decommissioning costs, risks of contamination, and the as-yet unsolved issue of long-term waste disposal. Electricity generated from renewable sources has several limitations that need to be overcome, including intermittency, low power density, and relatively high costs for solar power compared to coal-fired electricity (at least when the latter excludes external environmental and social costs). These are merely preliminary observations; we still require detailed analyses to determine the life cycle net energy returns of all of the alternative energy sources, including their supporting capital infrastructure.

Owing to the constraints, costs, lead times, and risks attached to developing alternative energy sources, a nationwide programme of energy conservation and efficiency is imperative to address the oil supply challenge. In fact, conservation should be the first priority, since it offers opportunities to capture “low hanging fruit” that are cheaper and easier to implement and can create time and budget space for constructing new infrastructure to deliver alternative energy sources in the longer term. The next chapter explores the potential for fuel savings in the transport sector, which consumes the bulk of oil products in South Africa.

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