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Life-Cycle Energy Balance and Greenhouse Gas Emissions of Nuclear Energy in Australia

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Life-Cycle Energy Balance and Greenhouse Gas Emissions of Nuclear Energy in Australia

A study undertaken for the Department of Prime Minister and Cabinet of the Australian Government

by

ISA, The University of Sydney, Australia

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Executive Summary

This report distils in a condensed yet comprehensive way a large body of previous work and knowledge about the energy balance and life-cycle greenhouse gas emissions associated with the nuclear fuel cycle. For comparison, a summary of the energy balance and life cycle emissions for a range of non-nuclear electricity generation technologies is also presented.

Certainly, every practical life-cycle assessment is undertaken for particular circumstances, that is particular locations, ores, or reactor types. Results from the literature must therefore be interpreted as valid primarily under these circumstances. Changing critical parameters and assumptions will lead to variations of the results.

Also, every practical life-cycle assessment leaves out some more or less important part of a theoretically "true" life-cycle, be it parts of the fuel cycle processes, indirect, upstream inputs into components, or parts of the material fuel and waste stream.

In bringing together analyses that are all incomplete with regard to a different aspect of the nuclear fuel cycle, and in extrapolating the results from these analyses towards a more complete "integrated" assessment, this work has achieved comparisons between nuclear energy systems that are very different in terms of a large number of critical technical parameters, operate in low- and high-carbon economies, and are assessed using different methods.

This study has also provided an example that demonstrates both the strength of state-of-the-art life-cycle methods for informing national policy, and the need for quality data underpinning this method.

Assumptions and scope of this life-cycle analysis of nuclear energy in Australia

The assumptions outlined below form the base case of our assessment. In a sensitivity analysis, these assumptions were varied, and the energy balance and greenhouse gas emissions re-calculated. A spreadsheet calculator was developed which allows these parameters to be set to any desired scenario.

An Australian nuclear fuel cycle is – except for mining and milling – hypothetical, and has been constructed based on the best knowledge and overseas experience available. Ideally, a more detailed **life-cycle assessment** than the one carried out in this work would exploit detailed planning and engineering data for concrete Australian facilities, in conjunction with an Australian input-output database.

The energy requirements for **mining and milling** as well as the **recovery rate** depend critically on the grade of the uranium-bearing ore, and on whether uranium is mined together with other products. In this study we have assumed that uranium is recovered from ore of 0.15% grade (typical grade for Ranger and Beverley mines), and that no other product is mined, so that the full energy requirement is attributable to uranium. This is a conservative assumption, because had we assumed conditions as in the Olympic Dam mine, the ore grade would have been lower (around 0.05%), however most energy requirements would have been attributable to the recovered copper.

The energy requirements for **enrichment** depend critically on which enrichment method is employed. In this study we have assumed the present mix of diffusion and centrifuge

plants (30/70%). For future scenarios this is a conservative assumption, because it is expected that in the future centrifuge plants will substitute diffusion plants.

The energy requirements for the **construction, operation and decommissioning** of nuclear facilities depend critically on what method is used for their enumeration. We have based this study on input-output hybrid life-cycle assessments.

The energy requirements for **mine clean-up**, **intermediate storage and long-term disposal** of nuclear waste depend critically on which procedures are deemed acceptable for sufficiently isolating radioactivity from the natural and human environment. At present, there is no operating final disposal facility, and hence limited practical experience of containing radioactivity for very long periods. This study does not comment on the adequacy of existing and planned mine clean-up, storage and disposal procedures, because these aspects fall outside this study's scope.

The **lifetime of uranium resources** for supplying the world's nuclear power plants depends critically on assumptions about future electricity demand, recoverable resources and ore grade distributions, by-products of uranium in mines, future exploration success, the exploitation of breeder reactors and plutonium in MOX fuels, and market conditions. These aspects are outside the scope of this study.

Results for the nuclear fuel cycle in Australia

The energy balance of the nuclear fuel cycle involves trade-offs between material throughput and fissile isotope concentration at various stages in the cycle. For example, there are trade-offs between

- using less but enriched fuel in Light Water Reactors, versus more but natural fuel in Heavy Water or Gas-cooled Graphite Reactors,
- applying more enrichment work to less fuel, versus less enrichment work to more fuel, and
- investing more energy into uranium and plutonium recycling, versus higher volumes of fuel uranium mining, throughput, storage, and disposal.

The overall **energy intensity of nuclear energy** depends critically on

- the grade of the uranium ore mined,
- the method for enrichment,
- the conversion rate of the nuclear fuel cycle (i.e. fuel recycling).

The energy intensity will increase

- with decreasing uranium ore grades,
- with increasing proportion of diffusion plants, and
- with decreasing fuel recycling.

Notwithstanding these variations, it can be stated that

- accepting the qualifications and omissions stated,
- for grades of average ore bodies mined today, and
- for state-of-the-art reactors and uranium processing facilities,

the energy intensity of nuclear power

- is around 0.18 kWh_{th}/kWh_{el} for light water reactors, and around 0.20 kWh_{th}/kWh_{el} for heavy water reactors,

- is slightly higher than most figures reported in the literature, because of omissions in the nuclear fuel cycle and upstream supply-chain contributions,
- varies within the range of 0.16-0.4 kWh_{th}/kWh_{el} for light water reactors, and within 0.18-0.35 kWh_{th}/kWh_{el} for heavy water reactors,
- is lower than that of any fossil-fuelled power technology.

The **energy payback time of nuclear energy** is around 6½ years for light water reactors, and 7 years for heavy water reactors, ranging within 5.6-14.1 years, and 6.4-12.4 years, respectively.

The **greenhouse gas intensity of nuclear energy** depends critically on

- the energy intensity,
- the proportion of electric versus thermal energy in the total energy requirement,
- whether electricity for enrichment is generated on-site (nuclear), or by fossil power plants, and
- the overall greenhouse gas intensity (i.e. fuel mix) of the economy.

The greenhouse gas intensity will increase

- with increasing energy intensity,
- with increasing proportion of electricity in the energy requirement,
- with increasing proportion of electricity for enrichment generated by fossil power plants, and
- with increasing greenhouse gas intensity of the economy.

Similarly,

- accepting the qualifications and omissions stated,
- for grades of average ore bodies mined today, and
- for state-of-the-art reactors and uranium processing facilities,

the greenhouse gas intensity of nuclear power is

- around 60 g CO_2-e/kWh_{el} for light water reactors, and around 65 g CO_2-e/kWh_{el} for heavy water reactors,
- slightly higher than most figures reported in the literature, because of omissions in the nuclear fuel cycle and upstream supply-chain contributions,
- varies within the range of 10-130 g CO_2-e/kWh_{el} for light water reactors, and within 10-120 g CO_2-e/kWh_{el} for heavy water reactors,
- lower than that of any fossil-fuelled power technology.

Sensitivity analysis

Significant parameters and assumptions influencing the energy and greenhouse gas intensity of nuclear energy are

- the grade of the uranium ore mined,
- the enrichment method and product assay,
- the nuclear power plant's load factor, burn-up, and lifetime,
- the greenhouse gas intensity and electricity distribution efficiency of the background economy.

In a sensitivity analysis, these parameters were varied and the energy and greenhouse gas intensity of nuclear energy re-calculated. This sensitivity explains the ranges of both the energy and greenhouse gas intensity of light water reactors and heavy water reactors.

Other electricity technologies

A comparable analysis has been undertaken for a number of conventional fossil-fuel and renewable electricity technologies. As with the methodology for the nuclear case, a range of literature values and current estimates have been used to examine the performance of these technologies in an Australian context, assuming new capacity is installed at close to world's best practice. These results, together with a summary of the nuclear energy results, are presented in the table below. The figures in parentheses represent the likely range of values. It is clear from the results that the fossil-fired technologies have significantly higher energy and greenhouse intensities than the other technologies.

Electricity technology	Energy intensity (kWh_{th}/kWh_{el})	Greenhouse gas intensity (g CO_2-e/kWh_{el})
Light water reactors	0.18 (0.16 – 0.40)	60 (10 – 130)
Heavy water reactors	0.20 (0.18 – 0.35)	65 (10 – 120)
Black coal (new subcritical)	2.85 (2.70 – 3.17)	941 (843 – 1171)
Black coal (supercritical)	2.62 (2.48 – 2.84)	863 (774 – 1046)
Brown coal (new subcritical)	3.46 (3.31 – 4.06)	1175 (1011 – 1506)
Natural gas (open cycle)	3.05 (2.81 – 3.46)	751 (627 – 891)
Natural gas (combined cycle)	2.35 (2.20 – 2.57)	577 (491 – 655)
Wind turbines	0.066 (0.041 – 0.12)	21 (13 – 40)
Photovoltaics	0.33 (0.16 – 0.67)	106 (53 – 217)
Hydroelectricity (run-of-river)	0.046 (0.020 – 0.137)	15 (6.5 – 44)

Methodology and data

Hybrid input-output-based life-cycle assessment is the most appropriate method to use for the analysis of energy and greenhouse gas emission balance of nuclear energy.

A comprehensive life-cycle assessment of the nuclear fuel cycle in Australia requires

- cost specifications and engineering data on the mining, milling, enrichment, power generation, storage and disposal facilities, and
- data on the background economy supporting such a nuclear industry indirectly.

The reliability of an input-output-based life-cycle assessment relies critically on the quality of the underpinning input-output data. In particular, given that hybrid input-output-based life-cycle assessment is an internationally accepted standard for investigating resource issues, it is essential that Australia possesses a detailed and complete input-output database.

The need for further analysis

Energy and greenhouse gas emissions analyses of energy supply systems are not a substitute for, but a supplement to economic, social, and other environmental considerations. If an energy supply system can be shown to a clear energy loser, then energy analysis is sufficient to argue that the program should be abandoned. If, on the contrary, the system appears to be an unambiguous energy producer, the decision whether or not to proceed with the program must also be based on other economic, social and environmental criteria.

The project team makes the following observations:

1. Further analyses of energy scenarios for Australia would benefit from an extended multi-criteria life-cycle analysis incorporating additional **social, economic and environmental indicators spanning the entire Triple Bottom Line**.

2. Most previous life-cycle studies documented in the literature use static methods that do not take into account temporal profiles of energy sources and sinks occurring in the full energy cycle, and the temporal interplay of net supply and demand for electricity. The current study could be enhanced by
   - developing a **dynamic formulation** of a time-dependent future profile of energy supply from a mix of sources; and
   - undertaking a **long-term forecasting exercise** of the transition of Australia's electricity generating system to a new mix of nuclear, advanced fossil, and renewable technologies, and the economy-wide TBL implications thereof.

3. In order to enable sound life-cycle assessments of the implications of energy systems for our environment, our physical resource base, and our society, it is essential that these assessments are underpinned by a **detailed and complete information base**. Australian life-cycle assessment capability would benefit from an enhanced data collection effort at the national level, in particular with view to creating a seamlessly aligned input-output database.

1 Project Objective

1.1 Rationale

The Uranium Mining Processing and Nuclear Energy Review Taskforce is undertaking an objective, scientific and comprehensive review of uranium mining, processing and contributions of nuclear power to the energy mix in Australia over the longer term. The Prime Minister has asked the Taskforce to report by the end of this year.

As part of this review, the Taskforce is examining the potential for Australia's uranium resources to contribute to global greenhouse gas abatement.

This requires an examination of the energy use and greenhouse gas emissions associated with the nuclear fuel cycle, including the mining of Australian uranium, conversion and enrichment, fuel fabrication, construction and operation of nuclear power stations, decommissioning and waste treatment and disposal.

It is important that a clear and comprehensive analysis of the life-cycle of nuclear power be articulated for an Australian audience, to improve the knowledge base relevant to this contentious and complex issue.

The aim of this study is to determine the life-cycle energy use and greenhouse gas emissions associated with producing electricity from Australian-mined uranium. This study

- reviews and evaluates existing international studies of nuclear power;
- identifies the major variables and determinants of energy use and greenhouse gas emissions for each stage of the nuclear fuel cycle;
- develops detailed estimates of energy use and greenhouse gas emissions for each stage of the nuclear fuel cycle under a set of agreed conditions;
- provides and justifies all methodologies, assumptions and references;
- develops and provides a spreadsheet-based tool to enable scenario planning and sensitivity analysis of the results.

The study also includes a desktop review of published studies of the life cycle energy use and greenhouse gas emissions for other specified electricity technologies in Australia. The summary of the results from these studies enables a comparison of the relative energy and greenhouse gas intensity of these technologies with those of nuclear power.

1.2 Structure of this report

Section 2 of this report describes and compares methodologies which are commonly used for energy and greenhouse gas accounting. Advantages of each method are presented together with their pitfalls and any sources of inaccuracy, and with a conclusion of the method used in this report for the life-cycle assessment of a nuclear industry in Australia. Section 3 reviews the available literature relating to energy and greenhouse gas emissions over the life cycle of nuclear power. Data available on each of the steps in the fuel cycle, reactor construction and operation are reviewed. Discrepancies between studies are highlighted together with the probable causes. In Section 4 we present short- and longer-term scenarios for nuclear power in Australia. The fuel cycle and reactor technology options chosen are described in detail and justified in the Australian context. Section 5 describes assumptions and justifies figures used in our analysis, followed by a presentation of the energy balance and greenhouse gas emissions of nuclear energy in Australia. Section 6 analyses published energy and greenhouse gas analyses for a range of selected non-nuclear power technologies and applies them to Australia for comparison. Conclusions of our analyses are presented in Section 7. The project team is described in Section 8.

2 Energy and greenhouse gas accounting: a brief methodology description

Summary

Energy and greenhouse gas accounting have been established over the past four decades as a sophisticated quantitative approach for the analysis of the energy balance and greenhouse gas emissions associated with energy supply systems. There are a number of completed large international projects that have examined a range of energy supply technologies in a comparative way.

Two basic methods – process analysis and input-output analysis – have been combined into a powerful hybrid life-cycle method. Input-output-based hybrid life-cycle assessment is now used around the world, providing both completeness and accuracy of the life-cycle inventory. This report also uses input-output-based hybrid life-cycle assessment in order to analyse the energy balance and greenhouse gas emissions from a nuclear industry established in Australia.

Different energy supply technologies can be compared in terms of their energy and greenhouse gas *intensities*. In the case of power plants, these quantities describe how much primary energy is required and greenhouse gases emitted, respectively, for the construction, operation and decommissioning of all system components, per kilo-Watt-hour (kWh) of electricity generated. The higher the energy intensity, the longer the power plant needs to "pay back" its own energy investment.

While energy and greenhouse gas intensities are static measures of resource and environmental performance, which look at different power plants in isolation. If large interconnected energy systems are examined using these measures, double-counting of energy and greenhouse gas embodiments may occur. In order to obtain more realistic results for the energy transition of entire economies, analysts should apply responsibility-sharing schemes, or dynamic modelling techniques that examine entire energy systems in conjunction with the economy that they are embedded in.

2.1 Methods of energy and greenhouse gas accounting

Energy analysis was developed in the 1970s for the assessment of both direct and indirect energy requirements for the provision of goods and services [1, 2]. Indirect or "embodied" energy is understood as the energy expended throughout the entire life cycle of the commodity, including raw materials, equipment, and infrastructure. Initially, a bottom-up approach, *process analysis*, was taken, where energy requirements of the main production processes and some important contributions from suppliers of inputs into the main processes are assessed in detail (for example by auditing or using disparate data sources), and where the system boundary is usually chosen with the understanding that the addition of successive upstream production stages has a small effect on the total inventory. At the Institute for Energy Analysis, which was established in Oak Ridge, Tennessee in 1974, guidelines were set for the investigation of energy supply and conversion systems – including the nuclear fuel cycle – in terms of the net energy output or the energy service delivered to the consumer ([3, 4]; Box 2.1).

"It takes energy to get energy – to extract, process, and transport fuels; to build energy conversion facilities; and to offset or avoid adverse environmental effects of energy production. Net energy analysis of an energy supply system involves identification and computation or measurement of the energy flows in society that are needed to deliver energy in a particular form to a given point of use. These flows are then compared to the energy converted or conserved by the particular system under consideration. […]

Net energy accounting is inherently interesting and worthwhile because it provides a deeper and more explicit understanding of the interdependence of the energy-producing sectors of our economy with each other, with other sectors of the economy, and with the natural environment. However, it is especially motivated at this time by a concern that the new energy technologies on which our future welfare will depend may require more energy themselves than does our present energy supply system based on relatively accessible fossil fuels. […] For the established energy supply technologies, net energy questions arise because of declining accessibility of resources. For every type of mineral resource, including energy resources (coal, oil, gas, uranium, and oil shales), the most easily recovered deposits – so far as we can identify them – are exploited first. As the resource is depleted, the less accessible (though often larger) deposits may require increasingly large energy expenditures per unit of useful work, until ultimately further exploitation would cease to yield a net energy output under any foreseeable circumstances. In physical terms, net energy analysis can directly identify the practical lower quality limits of the resource and may guide and supplement economic evaluation of the resource base. In addition, there is a growing awareness that careful energy husbandry may have benefits not easily translatable into conventional economic terms; that our natural environment has limited capacity to absorb energy releases and associated waste products; and that future generations have a valid claim on the earth's expendable resources."

Box 2.1: Net energy analysis (from [3], pp. 1-3).

More recently, process analysis was adopted in the official guidelines for life-cycle assessment (LCA) set out by the Society of Environmental Toxicology And Chemistry (SETAC; [5]), which in turn are widely used in LCAs of energy systems such as the ExternE project of the European Commission [6], the DECADES project of the International Atomic Energy Agency and others [7, 8], the German GEMIS project of the Öko-Institut and the Gesamthochschule Kassel [9], or the Swiss GaBE project [10].

It was already recognised in early studies, that process analyses carry significant systematic errors due to the unavoidable truncation of the system boundary ([11-14]; [3] Sec.5.6).[1] It was therefore suggested by Herendeen, Hannon, and others at the Center for Advanced Computation in Urbana, Illinois, to employ input-output analysis in order to account for energy requirements originating from inputs out of upstream supply chains of infinite order [15, 16]. Since this statistical, top-down approach suffers from various shortcomings such as aggregation and allocation errors, Bullard and co-workers [17] developed a *hybrid analysis* technique, combining advantages of process and input-output analysis, that is completeness and specificity ([18]; [3] Sec.5.5). With increasing recognition of the threat of anthropogenic climate change in the 1980s, the emphasis in assessments of energy supply and conversion systems shifted from net energy to embodied greenhouse gas emissions. Despite this, greenhouse gas analyses are still carried out using process, input-output, and hybrid techniques (for comparisons see [2, 19-23]).

Both process and input-output analysis yield energy and greenhouse gas coefficients, or *intensities*. In order to apply these to the calculation of energy and greenhouse gas requirements of energy supply systems, it is necessary to prepare a bill of inputs for each processing stage of the system, including construction, operation, infrastructure, and end-of-life. In the case of input-output analysis, this bill lists the monetary value of each input, which is subsequently assigned to an appropriate production sector in the input-output database.[2] One shortcoming is that a particular input (for example enriched uranium, or heavy water) may not be well represented by its assigned sector (chemicals) [32]. This sometimes occurs because input-output tables generally are not constructed with energy or environmental analysis in mind. If the vector of inputs is large, i.e. specifies many components, the inclusion of "atypical products" may not dominate the overall results since stochastic errors may cancel each other out [12, 33]. In cases where the atypical product problem is significant it can be solved by incorporating detailed process data wherever the input-output database is too aggregated (see for example [34] p. 19). This procedure employs input-output analysis to obtain a first complete estimate of the life cycle, and to streamline further

[1] It has been argued that – for comparative purposes – process analysis is sufficient since the indirect energy "overheads" of commodities do not vary much. This view has been refuted by Lenzen and Treloar [14] who demonstrate cases where the ranking of alternative options reverses in the transition from process to input-output analysis.

[2] An alternative to using monetary inputs and multipliers, is a *mixed-units* input-output framework, in which multipliers are expressed in physical units such as Megajoules or Litres or Employment-years [24-31]. However, such mixed-unit calculations are only possible for industry sectors that are sufficiently homogeneous (such as water supply, coal mining, etc), and not for sectors with inhomogeneous output (for example clothing, financial services, etc). Similarly, an extension to conventional input-output variants that only include short-term current transactions are so-called *semi-closed* input-output models. In these models long-term capital transactions (which in the National Accounts are traditionally treated as final demand) are endogenised into intermediate demand.

process data collection based on most important contributions [17, 35]. Used in unison, process and input-output analysis hence form a hybrid analysis that covers specific features of the energy supply system, and that is at the same time free from truncation errors [17, 18].

Hybrid input-output-based life-cycle assessment (IO-LCA) is a static, *ex-post* technique. As such, using hybrid IO-LCA, it is impossible to precisely quantify future changes in energy consumption and greenhouse gas emissions that would occur under real-economy shifts in energy supply technology. In general, results of IO-LCAs for energy and greenhouse gas embodiments of two alternative energy supply systems do not equal changes in energy consumption and greenhouse gas emissions caused by a corresponding shift from the current to the alternative energy supply system because IO-LCA assumes that (1) all commodity prices stay constant, (2) there are no changes in overall production technology and no input substitution in industries, (3) there are no constraints on production factors, such as labour supply, and (4) production costs are linear functions of production output. The last condition applies to production situations where there are no economies of scale, and where average costs equal variable costs, that is, fixed costs are zero. Since none of the above conditions is satisfied in reality, the energy and greenhouse gas embodiments calculated for future energy scenarios are only indicative of a future situation under real-economy demand or supply shifts (compare [36], p. 431, and Box 2.2).

> "*[…] the calculation of energy expenditures for future energy technologies is based upon recent patterns of energy use and technology. In effect our expenditures are average energy requirements for the technology in question calculated at the margin of the industrial system in the recent past. This means we are implicitly assuming that none of the supply systems or supporting industries under study is large enough to perturb the existing data.*
>
> *Broadly interpreted, the question of net energy from developing technologies involves not only the particular characteristics of the new source or technology, but also speculations about the industrial system within which the new technology might be expected to ply a major role. So interpreted, however, the question of net energy does not have a unique answer. Substantial changes in the energy supply system, particularly in energy prices, will produce important changes in industrial practice, as will changes in the supply of other factors of production. At present, it is virtually impossible to specify what even the major changes might be. At best, one can only postulate a particular set of possibilities. We recommend, therefore, that net energy analysis not be subjected to the additional uncertainties inherent in speculations about the nature of the future industrial context […]. Therefore, the differences between net energy performance indexes for alternative future energy technologies may have more meaning than the absolute value of these indexes.*"

Box 2.2: Net energy analysis of future energy supply systems (from [3], pp. 25-26).

The first comparative reviews of energy analyses of energy supply systems were published in the 1970s [37-39]. Full-energy-chain (FENCH) studies and net energy

analyses were reviewed more recently by van de Vate [40, 41] and by the International Atomic Energy Agency (IAEA) [2]. A number of mostly process analyses of electricity generation systems are discussed in proceedings published by the IAEA [42, 43], and by the OECD and International Energy Agency [44].

In the following, we will specify which accounting method was used in previous studies, whenever such information is available.

2.2 Energy and greenhouse gas intensity

Total energy and greenhouse gas emissions associated with an energy supply system will obviously depend on the size of the system. Quite simply, a larger system generates more electricity, but also consumes more resources and causes more emissions. Hence, when comparing different systems there is a need to describe energy and greenhouse gas impacts as a function of some kind of output, known as the *functional unit*. There are a number of potential definitions for a functional unit of energy supply systems. A dollar of gross energy production could be used, but will not explicate effects of different pricing arrangements. The capacity of the power supply is another useful means of comparison, and is an important facet of grid management. Capacity refers to the rate at which power can be supplied, and sufficient capacity must be available for grid managers to meet peak demands, especially if unexpected supply outages occur. However, in the case of renewable power, some technologies exhibit relatively low capacity, due to the reliance on natural conditions such as wind velocity and solar insolation. Thus, for the purpose of this report, the actual quantity (in kWh) of electricity delivered is perhaps the most inclusive and precise, and therefore most often used form of output measurement across renewable and non-renewable electricity supply systems. The use of a kWh as the functional unit, however, does not include the importance of downstream electricity delivery effects such as location of demand and relative time of demand and supply (see Sections 2.7 and 2.8).

We define the *load factor* or *capacity factor* λ of an energy supply system as the equivalent percentage of time over one year during which the system supplies electricity at 100% load, that is supplies electricity at its nominal power rating P. For example, a 1000 MW power plant running constantly at 800 MW power output has a load factor of 80%. Equally, a 1000 MW power plant running for 292 days a year at 1000 MW has a load factor of 80%.

The energy intensity η of an energy supply system of power rating P and load factor λ, is defined as the ratio of the total (gross) energy requirement E for construction, operation, and decommissioning and the electricity output of the plant over its lifetime T:

$$\eta = \frac{E}{P \times 8760\, h\, y^{-1} \times \lambda \times T} \quad . \tag{2.1}$$

The inverse of the energy intensity is often called the *energy ratio*. In calculating E, it is a convention to a) exclude the energy from human labour, energy in the ground

(minerals), energy in the sun, and hydrostatic potential, and b) not to discount future against present energy requirements [3, 45]. This report follows these conventions.

Similarly, the greenhouse gas intensity γ of an energy supply system of power rating P and load factor λ, is defined as the ratio of total greenhouse gas emissions G for construction, operation, and decommissioning and the electricity output of the plant over its lifetime T:

$$\gamma = \frac{G}{P \times 8760\,h\,y^{-1} \times \lambda \times T} \quad . \tag{2.2}$$

2.3 Lifetime, load factor, and power rating

It is obvious that an increase in the assumed lifetime and load factor of an energy supply system causes a decrease of its energy and greenhouse gas intensities, because the lifetime electrical output increases. This influence can be eliminated by normalising the modelled energy and greenhouse gas intensities to a constant load factor of L, and a constant lifetime of Y years according to

$$\begin{aligned} \eta_{\text{norm}} &= \eta \frac{\lambda}{L} \frac{T}{Y} = \frac{E}{P \times 8760\,h\,y^{-1} \times L \times Y} \\ \gamma_{\text{norm}} &= \gamma \frac{\lambda}{L} \frac{T}{Y} = \frac{G}{P \times 8760\,h\,y^{-1} \times L \times Y} \end{aligned} \quad . \tag{2.3}$$

2.4 Net energy considerations

Net energy analysis is a particular variant of energy analysis, in that it is applied to energy supply or conservation systems [46]. In particular, the fact that energy supply systems may produce some of their own (energy) inputs leads net energy analysis to separate out these circular flows, and to formulate a range of definitions of net energy indexes ([3] Sec. 6.0, [2] pp. 15-17). For example, calling $E_{\text{out}} = P \times 8760\,h\,y^{-1} \times \lambda \times T$ the lifetime electricity output of a system, the inverse of the energy intensity, or the energy ratio R_1 is simply

$$R_1 = \frac{E_{\text{out}}}{E} \quad . \tag{2.4}$$

This ratio describes the amount of electricity delivered per unit of fossil energy expended on it throughout the economy ([3] Eq. 6.7). In computing the total energy requirement E, all its constituents must be of the same energy quality (the "valuation problem", see [45-47], especially [34] pp. 5-9 for the case of nuclear energy, and [48] p. 290 for a proposal to use exergy as a common currency). For example, consider a breakdown of the energy embodiments in E into electricity E_{e}, coal E_{c}, oil E_{o}, and gas E_{g}. Then R_1 is

$$R_1 = \frac{E_{\text{out}}}{E_{\text{e}} / R_{1,\text{fossil}} + E_{\text{c}} + E_{\text{o}} + E_{\text{g}}} \tag{2.5}$$

where $R_{1,\text{fossil}}$ is the energy ratio (around 30% in Australia [25]) of conventional fossil-fuelled power plants that are to be displaced by alternative energy supply systems. The electricity input has to be converted to its primary-energy equivalent: $E_{\text{e}} / R_{1,\text{fossil}}$ is the primary fossil energy needed by the economy (power plants and all their suppliers) to generate the electricity input E_{e} ([3] Eq. 6.4). An alternative to Eq. 2.5 is to express the energy requirement in the denominator in terms of electricity: The ratio

$$R_2 = \frac{E_{\text{out}}}{E\ R_{1,\text{fossil}}} \tag{2.6}$$

describes the amount of electricity delivered per unit of electricity that could have been produced by the background economy by using the primary energy E required to support the system under study ([3] Eq. 6.6). Finally,

$$R_3 = \frac{E_{\text{out}} - E_{\text{e}}}{E_{\text{c}} + E_{\text{o}} + E_{\text{g}}} \tag{2.7}$$

represents the *net* electrical energy delivered per unit of fossil *thermal* energy expended on it ([3] Eq. 6.9). Analogous definitions exist for η and η_{norm}.

Regarding nuclear power plants, Equation 2.5 applies to a situation where for example uranium enrichment occurs off-site, using conventional fossil power. Equation 2.7 applies to a situation where the uranium enrichment occurs on-site, using the nuclear plant's own electricity.[3]

Net energy analysis has been criticised on the grounds that defining a boundary for the energy feedback flows from and to the system is arbitrary (the "boundary problem"). Basically, energy supplied by a system to be used for its own operation is a *feedback* flow. Leach [46] has shown convincingly that these feedback flows could be defined to include only fuels produced and used on site (site boundary), energy for local or regional infrastructure created particularly for the plant (regional boundary), or even wider, national and ecological energy feedbacks. Net energy ratios as in Eq. 2.7 depend critically on the choice of this boundary, while the absolute net energy $E_{\text{out}} - E$ is unaffected ([46] p. 339).[4]

[3] One example is the EURODIF enrichment plant in the Rhone Valley, France, which is supplied with electricity by the Tricastin nuclear power plant [49].

[4] A similar problem exists in input-output economics, where researchers have discussed the meaning and appropriateness of diagonal elements in input-output tables. For example, Dorfman ([50] p. 205) state: "*we find it convenient to include the possibility that the industry does require some of its own product as necessary input in its production process. The importance of this is that in a dynamic model in which production takes time, the stocks of coal to be used in coal mining must be available before any new coal can be produced*". In a counter argument however, Georgescu-Roegen ([51] p. 260) correctly concludes that "*internal flows may exceed any value we please*".

Moreover, a number of researchers have pointed out the problematic case of having to allocate primary energy requirements to inhomogeneous outputs (the "joint production problem"). For example, a typical nuclear power plant produces electricity and plutonium. How should the energy requirements be allocated between the two outputs [32]? Leach [46] states the case of phosphate and gold mines in Florida and South Africa, which produce U_3O_8 as a by-product. Since the primary products of these mines are not fuels, one cannot allocate energy requirements on the basis of energy content. Leach also shows that allocation on the basis of weight or price can lead to inconsistencies, for example for commodities that are low in volume but expensive to access (for example platinum), or those that are not even traded in markets (for example plutonium). This criticism applies to both energy analysis and net energy analysis.

In this report we apply the energy ratio R_1, because this is the ratio that correctly translates into energy and greenhouse gas intensities. We will also follow a convention in energy analysis that uranium and plutonium are regarded as materials and not as a form of energy, and that all energy requirements are allocated to the electricity output [32, 33]. Obviously, this assumption leads to a conservative estimate of the energy intensity of electricity.

2.5 Energy payback time

Energy intensity η, and energy ratios R_1 and R_3 are related to the *energy payback time*. This is the time t that it takes the energy supply system to generate an amount of electricity $\frac{t\,E_{\text{out}}}{T}$ that – had it been generated conventionally – would have had a primary-energy embodiment $\frac{1}{R_{1,\text{fossil}}}\frac{t\,E_{\text{out}}}{T}$ equal to the system's energy requirement E.

$$t_{\text{payback}} = \eta_1 \times T \times R_{1,\text{fossil}} = \frac{R_{1,\text{fossil}}}{R_1} T \tag{2.8}$$

The energy payback time can be normalised just as the energy intensity. Note that the definition of an energy payback time implicitly assumes an initial energy sink associated with the construction of the energy supply system, followed by a continuous net energy source. This definition is less useful for technologies that are characterised with large energy sinks during stages towards the end of their lifetime [45]. Nuclear facilities, for example, require lengthy periods for dismantling and clean-up.

Energy payback times have been applied in dynamic simulations of large substitution or expansion programs, because the energy requirement for constructing plants and infrastructure effectively reduces power available for the remainder of the economy [21]. It can be shown theoretically that energy sinks and outputs break even if the doubling time of the plant construction program approaches the single-plant energy payback time [45]. However, there have been no reports of major programs where the

expansion rate, the energy feedback, or the energy requirement of the energy supply system were large enough to cause significant reductions in available power [45, 46].

2.6 Temporal profiles of energy supply and demand

The time-of-day characteristics of energy supply systems are important parameters for grid planning and load matching purposes. Major upgrades to grids are often driven by increasing demands for peak power – if high stress is placed on the grid by high demand, power outages are more likely, and subsequent 'brown-outs' can occur. Peak demands in Australia are more frequently occurring during hot afternoons of summer months when air conditioning use escalates. It has been suggested that in fact this is a natural advantage of some solar electricity technologies [52]. Ideally however "*comparisons between different energy supply systems, if they are to be made, must be with reference to […] identical load duration curves*" ([3], p. 13).

In order to take account of the output 'value' of different energy supply systems, a convolution integral over system output and demand could be made in order to incorporate a technology-specific "value" factor. This is beyond the scope of the current study. Hence, as stated above, nuclear and non-nuclear electricity technologies will be evaluated in terms of the functional unit of their electricity production (kWh), regardless of intermittency or supply profile.

2.7 Loss of load probability

Due to short-term variability (for example wind and sun), and seasonal variability (for example biomass), a percentage of nominal power must be available as additional back-up capacity in order to cover possible reductions in base-load capacity. This is not a new challenge for grid controllers – changes in supply can be addressed much the same as changes in demand. Further, there have always been probabilities associated with unexpected outages of conventional generation, and grids have been designed in order to offer a reasonable level of insurance against such outages. Key technologies for dealing with shorter term demand and supply fluctuations are pumped-storage hydroelectricity, gas turbines, and more recently energy storage systems such as flywheels batteries and fuel cells, though these are in their infancy for large scale grid applications {International Energy Agency, 2005 #5603}.

A factor known as the loss of load probability (LOLP) can be utilised in the planning of grid capacity to improve the comparative assessment of energy supply systems. For the present study though it will be assumed that the grid in general will ensure continuity of supply given fluctuations in the output of (mainly) renewable electricity technologies.

2.8 Site dependence

It is well known that the energy and greenhouse gas intensities of wind or solar energy technologies are particularly low on sites with high mean wind velocity or solar insolation. This effect is already covered by the load factor. There are additional

site-specific differences which relate to country-specific energy requirements for the manufacture of components for energy supply systems. The manufacture of a 500kW German-designed wind turbine in Brazil, for example, requires almost twice as much primary energy as its manufacture in Germany. This increase results mainly from different energy contents of steel, which are in turn due to differences in the steel production route and scrap utilisation between the two countries [53]. Nevertheless, German and Brazilian production are about equal in terms of CO_2, because 95% of Brazilian electricity is generated by hydroelectric plants. Similarly, a Danish on-shore farm of six 95 kW wind turbines manufactured from steel containing 88% scrap and 12% mined ore, and from copper containing 80% scrap and 20% mined ore, yielded an extraordinarily low energy intensity of only 0.014 $kWh_{in}kWh_{el}^{-1}$ [54, 55]. These figures demonstrate that energy intensities of energy supply systems can vary considerably with the country of manufacture.

Similar yet less pronounced results hold if the country of import origin for plant components is varied. Hondo et al [56] report 10% variations for fossil-fuelled Japanese power plants.

Moreover, the energy required for the international transport of raw materials or components may vary across locations. However, preliminary results show that transport energy is usually below 5% of the total energy requirement, even for large distances such as between Germany and India [57], and Germany and Brazil [53].

2.9 Multiple-counting in life-cycle analysis of large interconnected systems

In the same way as traditional Life-Cycle Assessment, energy analysis adds up all upstream energy requirements of the total energy output. In the example supply chain (electricity) in Figure 2.1, this is the energy required by the power plant, plus the energy required by the manufacturer of the fuel rods that the power plant buys, plus the energy required for rolling the sheet for the tubes encasing the fuel, plus the energy required to make steel, etc.

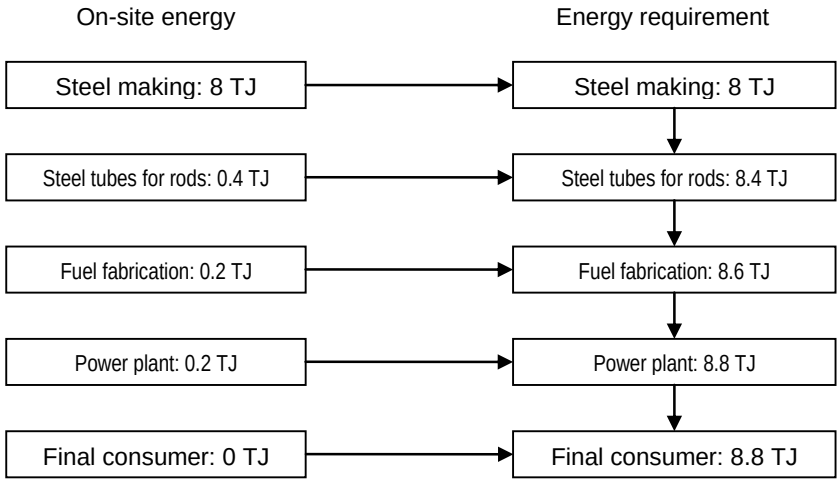

Figure 2.1: Multiple-counting of energy requirements, for one particular supply chain.

Assume for the sake of illustration that the participants of this supply chain do not supply anyone other than their successor. Imagine that the power plant, the producers of fuel rods, plus the steel tube maker and the steel works all use traditional LCA to calculate and publicise their energy balance. The energy required by the power plant supplying the consumer with electricity would appear in the consumer's energy balance, plus it would appear in the power plant's energy balance. It is hence double-counted.

The energy required for making steel appears in the energy balance of the steel works (as an on-site impact), in that of the steel tube maker, the fuel factory, the power plant, and the final consumer (as an upstream impact). Hence, it is multiple-counted (Figure 2.1). If every business and consumer in the economy used traditional LCA to calculate their energy requirement, the sum would be much greater than total national energy use. The National Energy Accounts would not balance. This can obviously not be right.

In particular, for a large energy supply system in an interconnected economy, the energy used in the steel works to make steel for the fuel rods might well come from the very nuclear power plant. Since conventional LCA does not take this into account, a systems perspective has to be applied.

2.9.1 Consumer or producer responsibility?

LCA is a method that assumes full *consumer responsibility*: its perspective of analysis is that of the consumer placed at the very end of the supply chain. All impacts incurred during production are heaped onto the consumer of products[5]. This is because LCA is intended to assess the environmental impact of competing technical options to supply products or services. Therefore, if double-counting is to be avoided, LCA can only be used for the *final* consumers in an economy: the impacts of any producer must be zero. An example for a National Energy Account applying consumer-responsibility is the Australian Bureau of Statistics' *Energy Accounts for Australia* [58] (Figure 2.2).

[5] What we mean here with "consumer" is not necessarily the final consumer, but any consumer of products. If that consumer is a producing entity (consuming operating inputs), then LCA adds the impacts of upstream supply chains originating from that entity.

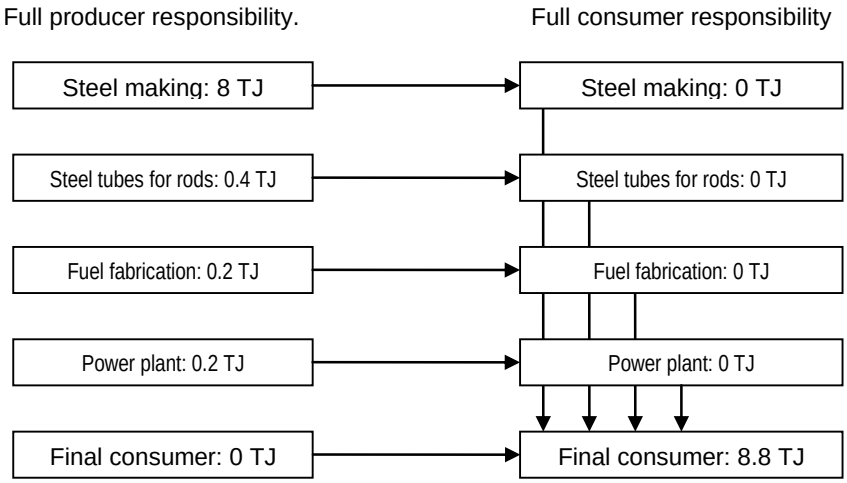

Figure 2.2: Full producer and consumer responsibility approaches to energy accounting, for one particular supply chain. The sum of all energy reported on is 8.8 TJ.

Other approaches assume full *producer responsibility*. For example, every country has to report their greenhouse gas emissions under the United Nations Framework Convention on Climate Change (UNFCCC). Some countries like Australia emit during the production of goods that are exported. These emissions appear in Australia's report, not in the report of the country that imports and consumes these goods. The literature contains some interesting debates about which approach is best [59-63]. An example for a National Energy Account applying producer-responsibility is the Australian Bureau of Agricultural and Resource Economics' *Energy Update* [64]. Full consumer and producer responsibility are consistent with the principles of National Energy Accounting in the sense that they do not lead to double-counting (Figure 2.2).

A particular disadvantage of full producer or full consumer responsibility is that they

- do not allow for *both* producers and consumers to simultaneously evaluate their energy requirement without double-counting;
- do not allow for producers to evaluate their *full life-cycle* energy requirement without double-counting.

The latter is – simply speaking – because every producer's on-site energy use is a part of the life-cycle of some other producer. Ultimately, within LCA, a part of every producer's on-site energy use will even appear in its own life-cycle. While for very small applications this effect is negligible, there will be a significant double-counting error in the case of large and heavily interconnected systems. Thus, it must be expected that most full-energy chain assessments of energy supply systems listed above are more or less affected by this error.

2.9.2 Shared responsibility

Full producer and consumer responsibility are not applicable if both producers and consumers are to report their energy requirements over the full life cycle. It is intuitively clear that responsibility is somehow shared between the supplier and the recipient of any commodity, because the supplier has caused the impacts directly, but the recipient has demanded that the supplier do so.

As with many other allocative problems, an acceptable consensus probably lies somewhere between producer and consumer responsibility. In order to assign responsibility to actors participating in these transactions, one has to know the respective supply chains or inter-industry relations. Hence, a problem poses itself in the form of the question: "How can one devise an accounting method that allows apportioning energy (or any other quantity) to both producers and consumers while avoiding double-counting?" This problem has been addressed in a recent publication by Gallego and Lenzen [65].

These authors develop the concept of shared responsibility, recognising that there are always two (groups of) actors who play a role in commodities produced and impacts caused, and two perspectives involved in every transaction: the supplier's and the recipient's. Hence, responsibility for impacts can be shared between them. Naturally, this applies to both burdens and benefits. Sharing impacts between each pair of subsequent supply chain stages – for example on a 50%-50% basis between the supplier and the recipient – gets rid of the double-counting problem (Figure 2.3).

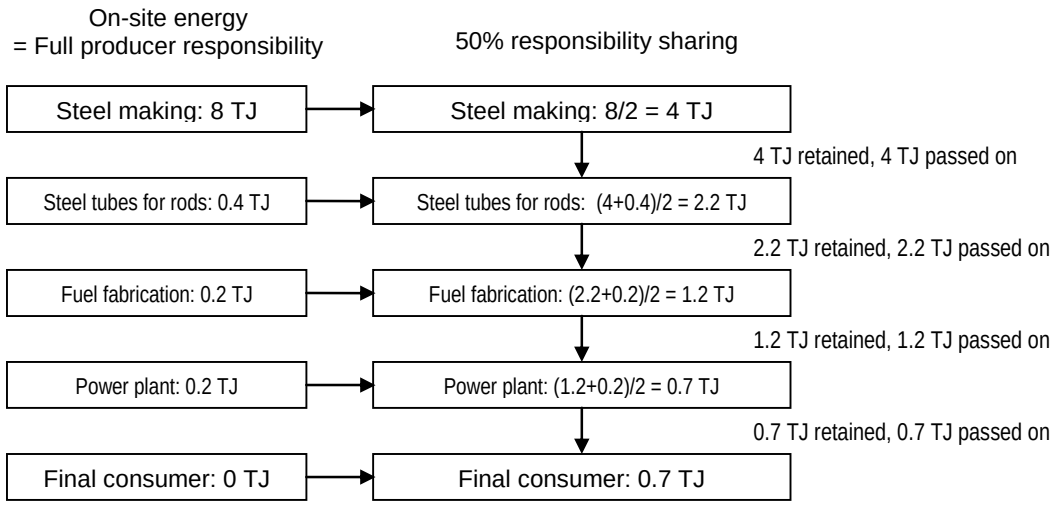

Figure 2.3: Shared producer and consumer responsibility in energy accounting, for one particular supply chain.

Adding up all energy requirements in Figure 2.3 above gives 8.8 TJ, which is required for accounting consistency. Each actor is allocated a share of each single energy requirement throughout the entire supply chain. These shares form a mutually exclusive and collectively exhaustive set of the energy used in the whole economy [66].

2.9.3 Multiple-counting issues in energy system analysis

Throughout the literature on the energy balance and greenhouse gas emissions of power plants, it is evident that authors strive to cover all energy and greenhouse gas contributions throughout the plant's entire supply chain. The more complete, each life-cycle assessment will invariably comprise impacts that would also appear in their suppliers' life-cycle assessment, were these suppliers to undertake one. These impacts are multiple-counted. In the case a small wind turbine, with an equally small supply chain, the multiple-counted energy and greenhouse gas portions may be small compared to the overall energy use and greenhouse gas emissions in the economy. Hence, the double-counting would hardly be noticeable in a national energy account.

Large power plants, and even more so whole energy supply systems and their supply chains, represent a significant proportion of the economy, if not in monetary terms, then certainly in energy terms. Full-supply-chain analyses of these systems will count amounts of energy and greenhouse gas emissions that would also be counted in analyses of other industries.

For example, assume a decision-maker had available two full-energy-chain life-cycle analyses, one of a number of nuclear plants, and one of a number of coal-fired plants. Both plant types deliver electricity to the final consumer (households) and to other industries. In the most likely case, the life-cycle inputs and outputs of these two systems will not be two separate lots: The energy output of one plant system will form part of the energy embodiment of the other, both through direct deliveries of electricity to each other (for example a coal-fired plant providing electricity to a nuclear power plant during re-loading) and through electricity requirements for the manufacture of components. Moreover, large energy supply systems will produce a significant proportion of the energy needed to produce the inputs into their own future operation. These contributions must in principle – in a net energy and greenhouse gas sense – be excluded from the life-cycle inventory. However, hardly any of the studies examined went as far as examining the connection of the power plants' electricity *output* with their supply chains. Hence, summing up over energy and greenhouse gas requirements of such two systems of power plants will likely overestimate the real energy and greenhouse gas implications of their installation.

If multiple counting is to be avoided in energy and greenhouse gas analyses of large interconnected systems, two methodological options can be pursued:

a) examine the plant or system in isolation, using a shared responsibility calculus [65, 66]; and
b) examine the plant or system in conjunction with the entire economy in which it is embedded.

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3 Energy and greenhouse gas emissions of nuclear energy: a literature review

This Section reviews existing energy and greenhouse gas life-cycle analyses of the nuclear fuel cycle[1], and determines the causes for the widely varying results of numerous previous studies. In particular, we report on the *energy* and *greenhouse gas intensity*, that is the ratio of the primary energy consumed, or greenhouse gases emitted during all stages of the nuclear fuel cycle, per unit of output of electrical energy over the lifetime of the electricity supply (see Section 2).

The results of this literature review will be used to support the energy and greenhouse gas life-cycle assessment of a nuclear fuel cycle in Australia. All assumptions for the Australian case are detailed in Section 5 of this report.

Throughout this review, two energy units will be used: J (Joules) and Wh (Watt-hours; 1 Wh = 3,600 J). These units refer to thermal energy, unless specifically marked with a subscript 'el'. J_{th}, J_{el}, Wh_{th} and Wh_{el} will be used interchangeably, especially where one form of energy dominates. For the use of energy ratios, Wh_{th} / Wh_{el} will be used, either as GWh, MWh or kWh. Older units such as kcal and BTU were converted.

Before embarking on a journey though the nuclear life cycle, it is instructive to obtain an idea of the energy density of uranium:

- Compared with the combustion of coal, the fission of uranium produces about three million times more energy per unit weight [3, 4]. The fission of one kilogram of $^{235}_{92}\mathrm{U}$ releases about **25 million kWh of heat**.
- A 1000 MW nuclear power plant operating at 91% load (8,000 hours a year at full load) with a thermal efficiency of 30% would have to generate about **27 billion kWh of heat** annually, thus theoretically requiring about one tonne of $^{235}_{92}\mathrm{U}$.
- Considering that additional fissile isotopes (for example $^{239}_{94}\mathrm{Pu}$, $^{241}_{94}\mathrm{Pu}$, and $^{233}_{92}\mathrm{U}$) are generated during the fission of $^{235}_{92}\mathrm{U}$ reduces the annual requirement for a 1000 MW plant to about **640 kg of** $^{235}_{92}\mathrm{U}$.
- This equates to about **30 tonnes of enriched uranium** (at 3% $^{235}_{92}\mathrm{U}$; taking into account that fuel rods are replaced after $^{2}/_{3}$ of the $^{235}_{92}\mathrm{U}$ is consumed), and to about **165 tonnes of natural uranium** (0.7% $^{235}_{92}\mathrm{U}$, 99.3% $^{238}_{92}\mathrm{U}$).
- Assuming ores with a uranium content of 2 ‰ yields **80,000 tonnes of ore** to be mined per year. For comparison, a 1000 MW coal-fired power plant operating 8,000 hours for one year at full load requires about **3 million tonnes of coal** [5].

[1] For an instructive description of the nuclear fuel cycle, and its mass balance, see the Vattenfall Environmental Product Declaration [1, 2].

3.1 Uranium mining

All fissile elements were created about 6 billion years ago in roughly equal proportions, probably during a supernova event. Amongst those elements that play a role in the nuclear fuel cycle, only uranium ($^{238}_{92}\mathrm{U}$ and $^{235}_{92}\mathrm{U}$) and thorium ($^{232}_{90}\mathrm{Th}$) still occur in nature, because their half lives are in the order of billions of years. Today, only 40% of the initially created uranium remains. One tonne of rock and soil contains on average 1 – 5 g of uranium (mostly as pitchblende U_3O_8, and as carnotite KUO_2-VO_4), and 3 – 20 g of thorium. Concentrations in sediments can reach magnitudes of about 1 kg of uranium per tonne. One tonne of sea water contains about 3 mg of uranium.

Amongst the two uranium isotopes, only $^{235}_{92}\mathrm{U}$ is fissile. Since the half life of $^{235}_{92}\mathrm{U}$ is about 1 billion years, which is smaller than that of $^{238}_{92}\mathrm{U}$ at 4.5 billion years, the concentration of $^{235}_{92}\mathrm{U}$ in natural uranium has decreased steadily. At the time of the consolidation of the earth, the concentration of $^{235}_{92}\mathrm{U}$ in natural uranium was about 30%. About 3 billion years ago it was about 4%.[2] Today it is 0.7%, with the remaining 99.3% being $^{238}_{92}\mathrm{U}$ [5].

Other potential plutonium and uranium isotopes such as $^{239}_{94}\mathrm{Pu}$, $^{241}_{94}\mathrm{Pu}$, and $^{233}_{92}\mathrm{U}$ have much shorter half lives and have completely decayed since their natural formation. Of the naturally occurring isotopes, only the rarer $^{235}_{92}\mathrm{U}$ has a large enough cross section for fission, and this only by thermal neutrons. Nevertheless, $^{238}_{92}\mathrm{U}$ and $^{232}_{90}\mathrm{Th}$ are of interest because they can be used for breeding $^{239}_{94}\mathrm{Pu}$, $^{241}_{94}\mathrm{Pu}$, and $^{233}_{92}\mathrm{U}$, which in turn are fissile.

Amongst the naturally occurring fissile isotopes, only uranium is mined for nuclear fuel purposes.[3] A deposit that is economically exploitable is called an ore. Uranium is extracted from these ores using either open-pit (30%) or underground excavation (38%), *in-situ* leaching (21%), or as a by-product in other mining (11%) [8, 9]. Amongst these techniques, open-pit excavation involves the largest quantities of materials to be removed, in-situ leaching the smallest [10]. In-situ leaching avoids having to mill the uranium ore. Techniques to extract uranium from sea water are under investigation [11].

[2] About 2 billion years ago, water entered into a natural uranium deposit near Oklo in today's Gabon in West Africa. At that time the concentration of the fissile 235-U happened to be about equal to its concentration in present reactor fuel bundles (around 3%). When the water entered the deposit, it effectively acted as a moderator, slowing down the neutrons emitted during decay events, activating a chain reaction, and thus creating a natural nuclear reactor. This underground reactor was to operate for another few 100,000 years, until the concentration of the 235-U was reduced to about 0.5%, and the reaction extinguished ([6, 7], as cited in [5]).

[3] Thorium has colouring properties that has made it useful in ceramic glazes. But, it has been most widely used in lantern mantles for the brightness it imparts, and in welding rods, which burn better with small amounts of added thorium. Thorium improves the properties of ophthalmic lenses, and is an alloying agent in certain metals used in the aerospace industry (http://www.epa.gov/radiation/radionuclides/thorium.htm).

	Reference	Year	Mass (million tonnes U)			
			weapon-grade	≥ 3‰	≥ 1‰	≥ 0.1‰
Pu stocks	[5]	1997	0.013			
U stocks	[5]	1997	0.13	0.3		
Known U reserves	[12]	1976			1.0	3.2
	[13]	2006		3.6		
	[14]	2006		4.7		
Estimated U reserves	[12]	1976			1.0	3.7
	[14]	2006				10

Table 3.1: Known and estimated world-wide uranium reserves.

Amongst the world's about 4.7 million tonnes of known uranium reserves (Table 3.1), Australia has the world's largest share (estimated at 25% of world supply [14], Fig. 3.1), as well as some of the world's largest uranium mines (Olympic Dam SA, Ranger NT, Beverley SA). All of Australian uranium production (≈ 10,000 t/year [15]) is exported for electricity generation (to USA, EU, Japan and South Korea) [13], however Canada is the world's largest exporter of uranium (Figs. 3.1 to 3.4).

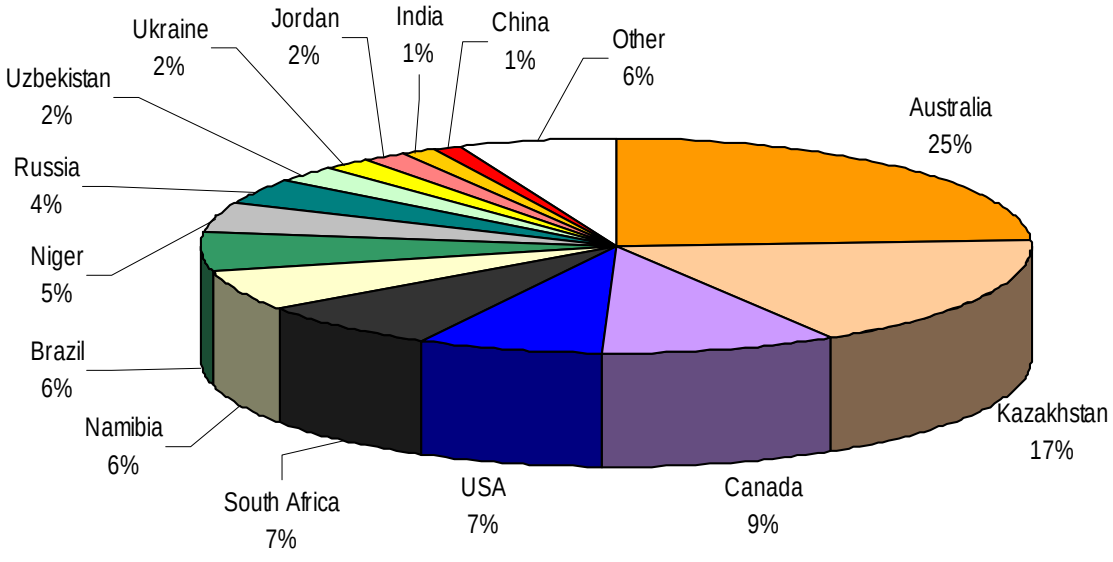

Figure 3.1: Country shares of world uranium reserves [14].

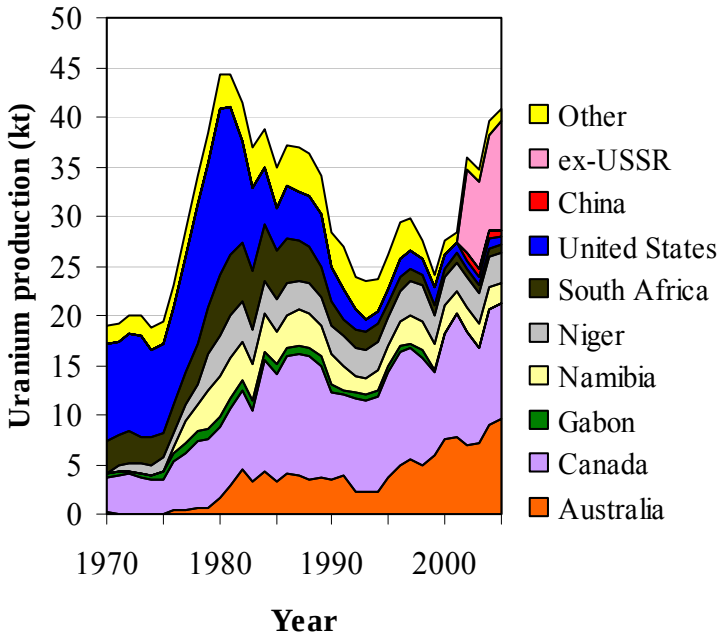

Figure 3.2: World production of uranium (after [16]).

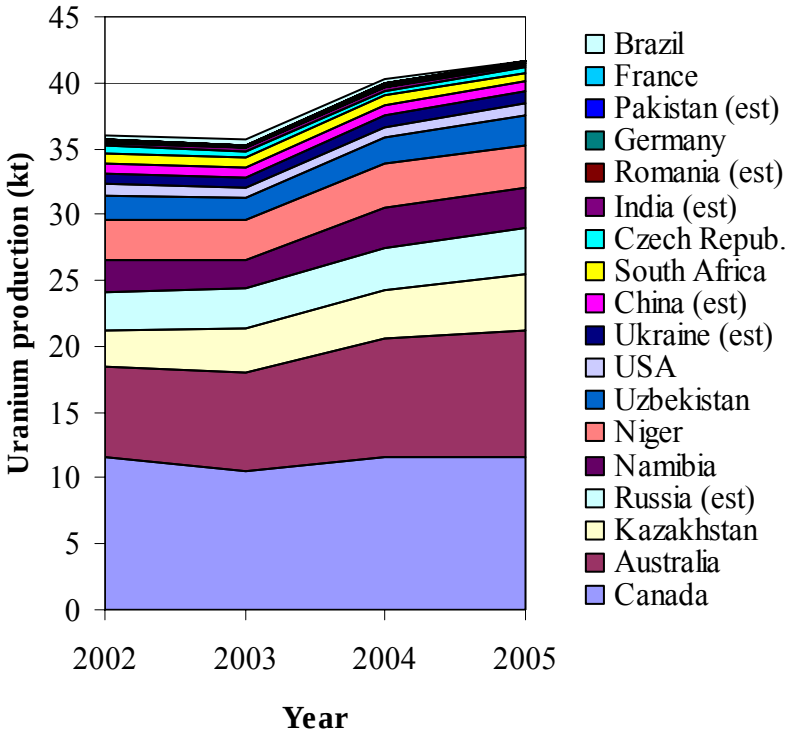

Figure 3.3: Recent world production of uranium (after [8, 13]; est=estimated).

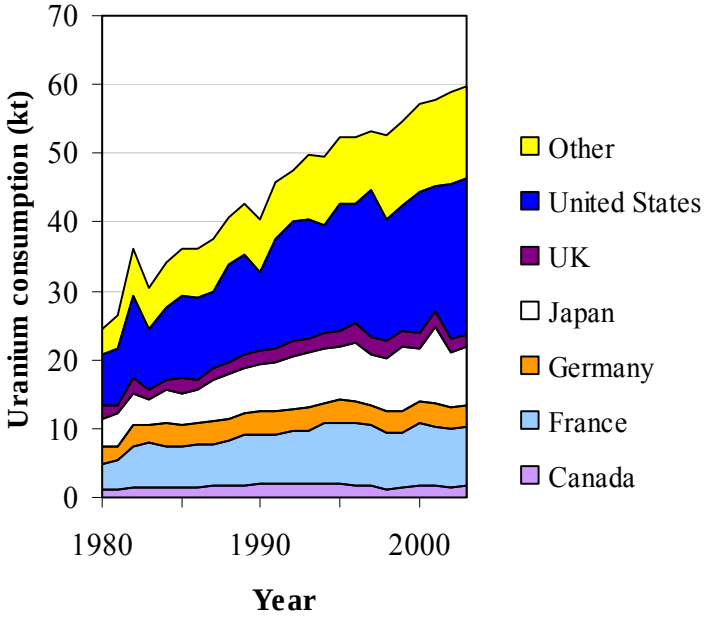

Figure 3.4: World consumption of uranium (after [16]).

Detailed data on the energy requirements of uranium mining are available from an input-output-based hybrid life-cycle assessment for the USA [17] (Table 3.2). Storm van Leeuwen and Smith [18] summarise 39 studies undertaken between 1968 and 2005, averaging 1.12 GJ per tonne of ore.[4] As in Storm van Leeuwen and Smith's study, averages of these values will be used in this report, complemented with data for Australian mine operations. Methane emissions from uranium mines are found to be negligible [21].

Refe-rence	Rock	GJ/t ore	GJ/t U @0.3%	GJ/t U @0.2%	GJ/t U @0.1%	GJ/t U @0.01%
Direct energy						
[17]	ore	0.61	292	439	877	8,774
[17]	shale	0.10	47	70	141	1,410
Indirect energy						
[17]	ore	0.76	362	542	1,085	10,847
[17]	shale	0.30	143	214	428	4,282
Total energy						
[19]	ore	1.21	403	605	1,210	12,100
[17]	ore	1.37	654	981	1,962	19,621
[17]	shale	0.40	190	285	569	5,692

Table 3.2: Specific energy requirements for uranium mining [17, 19].

[4] Extreme outliers (Orita 1995) were taken out of the average. A comparison of their figures for uranium milling with those from [19] shows that Storm van Leeuwen and Smith seem to directly add electrical and thermal energy, which is against recommended conventions [20]. They do give ratios of electrical to thermal energy, however for those references where a range of values is given, a correct reconstruction of electrical and thermal energy is impossible. We adopted their figures as they are stated as thermal energy, since the thermal energy outweighs electrical energy, in any case requiring only a small correction.

The lower the ore grade, the less uranium is recoverable from the reserves. The regression formula by Storm van Leeuwen and Smith [18] is represented by the dashed line in Figure 3.5.

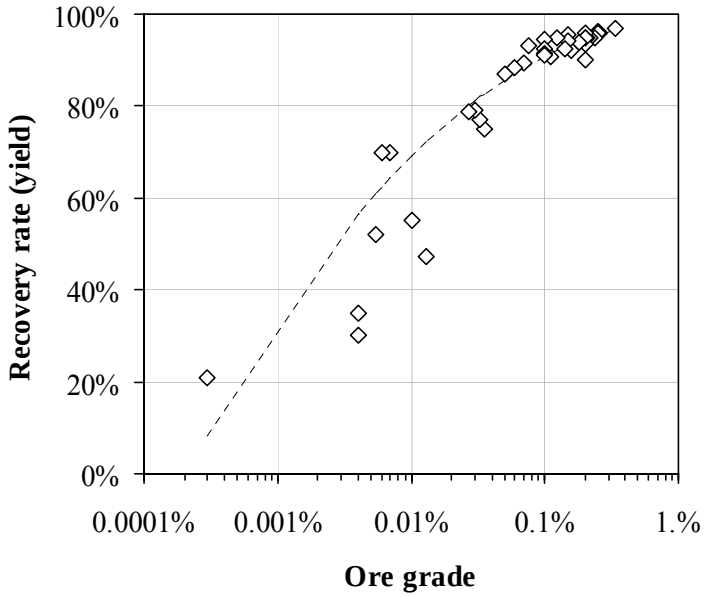

Figure 3.5: Uranium recovery rate as a function of ore grade (% U_3O_8). The dashed line represents Storm van Leeuwen and Smith's regression [18].

3.2 Uranium milling

Following extraction from the ground, the raw ore is milled (crushed and ground up), and uranium is chemically extracted by dissolving (using acid or alkaline solutions), and subsequent precipitation. Uranium milling is usually carried out close to the mine site in order to avoid having to transport large amounts of ore. The output of a uranium mill is dry uranium ore concentrate ("yellowcake"), usually packed in steel drums, containing above 80% uranium [10].

Once again, detailed data on the energy requirements of uranium milling are available from an input-output-based hybrid life-cycle assessment for the USA [17] (Table 3.3). Storm van Leeuwen and Smith [18] summarise studies undertaken between 1968 and 2005, averaging 1.66 GJ per tonne of ore.[5]

[5] The study on electric dissociation of granite was taken out of the average, as its energy intensity is an extreme outlier. A comparison of their figures for uranium milling with those from [19] shows that Storm van Leeuwen and Smith seem to directly add electrical and thermal energy, which is against recommended conventions [20]. They do give ratios of electrical to thermal energy, however for those references where a range of values is given, a correct reconstruction of electrical and thermal energy is impossible. We adopted their figures as they are stated as thermal energy, since the thermal energy outweighs electrical energy, in any case requiring only a small correction.

Refe-rence	Rock	GJ/t ore	GJ/t U @0.3%	GJ/t U @0.2%	GJ/t U @0.1%	GJ/t U @0.01%
Direct energy						
[17]	ore	0.82	390	585	1,169	11,695
[17]	shale	0.69	327	491	981	9,811
Indirect energy						
[17]	ore	0.53	250	375	751	7,509
[17]	shale	0.39	186	279	559	5,589
Total energy						
[19]	ore	1.13	375	563	1,125	11,250
[17]	ore	1.34	640	960	1,920	19,204
[17]	shale	1.08	513	770	1,540	15,400

Table 3.3: Specific energy requirements for uranium milling [17, 19].

3.3 Conversion to uranium hexafluoride (UF_6)

After milling or in-situ leaching, the uranium is converted into gaseous UF_6 in order to enable enrichment, that is the separation of the fissile $^{235}_{92}U$ from the practically non-fissile $^{238}_{92}U$. The conversion occurs by first purifying and reducing U_3O_8 to uranium dioxide UO_2 [1], which is then reacted with hydrogen fluoride (HF) to form uranium tetrafluoride (UF_4), which in turn is combined with gaseous fluorine to UF_6 in a fluidised bed reactor. The reaction of UO_2 with HF can occur either in a dry kiln, or by a wet process using aqueous HF [22]. The wet process uses significantly less energy [23]. The conversion into gaseous UF_6 is necessary no matter what enrichment method is employed.

Weis [23] states energy requirements for the wet process of only 7 MWh_{th} / tU. The Australian Coal Association's figures are 21 MWh_{el} / tU and 155 MWh_{th} / tU [24]. Rotty and co-workers state requirements of 14.6 MWh_{el} and 396 MWh_{th} ([17] pp. 63-64), with most of the energy needed is in form of natural gas. Their figure is also the highest in Storm van Leeuwen and Smith's literature review [18].

3.4 Enrichment

At its natural concentration of 0.7%, $^{235}_{92}U$ can be used as a reactor fuel only in particular reactor types (heavy-water reactors and high-temperature reactors). In order to be able to maintain a nuclear chain reaction in typical light water reactors, the concentration of $^{235}_{92}U$ in the uranium isotope mix has to be increased to about 3%. At present there exist a range of enrichment methods using UF_6 as feed. Since uranium isotopes do not differ in their chemical behaviour, enrichment techniques exploit their mass difference as a means for separating them [25]. These methods are:

- Gaseous diffusion: The heavier $^{238}_{92}\mathrm{U}$ isotope diffuses more slowly than the lighter $^{235}_{92}\mathrm{U}$: $v_{\mathrm{diff}}\left(^{235}_{92}\mathrm{UF}_6\right)/v_{\mathrm{diff}}\left(^{238}_{92}\mathrm{UF}_6\right)=\sqrt{m\left(^{238}_{92}\mathrm{UF}_6\right)/m\left(^{235}_{92}\mathrm{UF}_6\right)}$, v diffusion velocity, m mass. Enrichment from 0.7% to 3% $^{235}_{92}\mathrm{U}$ requires in the order of 1,000 consecutive separation cascades. In 2002, 40% of all enrichment plant used gaseous diffusion (mostly France and USA). This percentage is decreasing in favour of the centrifuge method.
- Gas centrifuge: The partial pressure of two gases (contained as a gas mixture in a rotating cylinder) depends on their masses. Centrifugal forces cause a radial concentration gradient, with the heavier isotope concentrated outside, and the lighter isotope concentrated inside. Enrichment from 0.7% to 3% $^{235}_{92}\mathrm{U}$ requires in the order of 10 consecutive separation cascades. In 2002, 60% of all enrichment plants used the centrifuge method (mostly Russia, Germany, UK, Netherlands, China, and Japan).
- Electromagnetic Isotope Separation (EMIS): Uses the magnetic separation principle of a mass spectrometer, albeit at a larger scale. Used for building the Hiroshima bomb, and in Iraq's nuclear program, but now outdated.
- Aerodynamic (jet nozzle) method: Exploits the same physical principle as the gas centrifuge, but creates a rotating gas mixture by injection into a circular jet. Demonstration plants built in Brazil and South Africa.
- Laser: The energy spectra, and therefore the ionisation energies of different isotopes depend on their masses. Using mono-energetic laser beams, one isotope can be preferentially ionised, and filtered out using an electrostatic field.

At the end of this stage, the enriched UF_6 is converted into uranium oxide (UO_2).

The energy needed for enrichment is partly dependent on the incremental enrichment factor for one cascade, which in turn determines the number of cascades necessary to achieve enrichment to around 3%. Gaseous diffusion needs more cascades than the gas centrifuges, and additionally requires the energy-intensive compression of UF_6 at the entry point of each cascade (Table 3.4). Gas centrifuges only require electrical energy for the rotation of the cylinders, and some heat in order to maintain an axial convection of the UF_6. Atomic laser techniques require the normally metallic uranium to be evaporated (using considerable heat energy), and then transferred into a vacuum, so that ions can be electrostatically filtered [25]. The Australian laser technique is based on molecular rather than atomic laser separation. Instead of having to maintain uranium atoms in a hot gas, the technique uses the already gaseous UF_6, and preferentially excites UF_6 molecules.[6]

[6] http://www.silex.com/.

Refe-rence	Year	Type	kWh_{el} / kg SWU	Comments
[5]	1997	C	170	converted using 3.5 SWU per kg 3%-U
[22]	2006	C	50	
[22]	2006	C	62.3	Urenco plant in the UK, figures includes "infrastructure and capital works"
[26]	1978	C	250	
[26]	1978	C	282	Including investment in the plant
[27]	1996	C	75	
[28]	2004	C	40	Urenco plants in Europe, TENEX plants in Russia
[5]	1997	D	2,860	converted using 3.5 SWU per kg 3%-U
cit. in [29]	1975	D	2,330 – 2,737	
cit. in [23]	1990	D	2,100 – 3,100	
[22]	2006	D	2,500	
[19]	1975	D	2,420	
[19]	1975	D	≈ 2,520	including capital
[17]	1975	D	2,810	
[17]	1975	D	3,050	including plant construction, fossil fuels and process materials
[26]	1978	D	3,080	
[27]	1996	D	2,400	
[28]	2004	D	2,400	Eurodif plant at Tricastin, France
[28]	2004	D	2,600	USEC Paducah (USA)
[5]	1997	L	700	
[22]	2006	E	≈ 25,000	
[3]	1983	A	3,000 – 3,500	
[22]	2006	A	> 3,000	
[26]	1978	A	3,080	

Table 3.4: Energy requirements for uranium enrichment (A: Aerodynamic method; C: Gas centrifuge; D: Gaseous diffusion; E: EMIS; L: laser).

	Operation excl electricity	Construction	Electricity	Energy in construction	Energy in operation	Total energy requirement
	\$/SWU	\$/SWU	kWh_{el}/SWU	kWh_{th}/SWU	kWh_{th}/SWU	kWh_{el}/SWU
Diffusion	7.5	52.5	2,400	151.7	21.7	2,458
Centrifuge	6.5	84.0	100	242.7	18.8	187
Jet nozzle	6.5	73.5	3,000	212.4	18.8	3,077
Laser	6.25	13.1	100	37.9	18.1	119
Chemical extraction	12.5	68.3	300	197.2	36.1	378

Table 3.5: Energy requirements for uranium enrichment [30].

Villani [30] summarises five enrichment technologies, distinguishing investment cost into the plants, operation excluding electricity, and electricity inputs. Multiplied with energy intensities given for the US by Penner, Herendeen and Milke [31][7] yield the results in Table 3.5.

The two tables above require an explanation of the unit SWU. Amounts of enriched uranium are usually expressed as *Separative Work Units* (for example tonne SWU).[8] There is a trade-off between the amount of natural uranium feed and the number of SWUs needed to produce enriched uranium. For example: in order to produce 10kg of uranium at 4.5% $^{235}_{92}\mathrm{U}$ concentration while allowing a tails assay of 0.3% requires 100 kg of natural uranium and 62 SWU. Asking for the tails to have only 0.2% assay limits the amount of natural uranium needed to 83 kg, but it also increases the separative work to 76 SWU. Hence, the optimal (tails assay) compromise between uranium feed and separative work depends on the price of natural uranium versus the cost of enrichment operating inputs. During times of cheap uranium, an enrichment plant operator will probably choose to allow a higher $^{235}_{92}\mathrm{U}$ tails assay, and vice versa. In terms of the energy balance of the nuclear fuel cycle this means that lower tails assays mean that less energy is spent on mining, milling and conversion, and more on enrichment, and vice versa ([17] pp. 26-36 & 43).

Storm van Leeuwen and Smith [18] summarise studies undertaken between 1974 and 2003, averaging 2,600 kWh/SWU for gas diffusion, and 290 kWh/SWU for gas centrifuges.[9] These values agree well with most of the additional references (Table 3.4).

3.5 Fuel fabrication

In the reactor, the fuel is contained within about 4 m long, hermetically welded tubes ("fuel rods"), about 100 of which at a time are combined into fuel bundles. The manufacture of fuel rods involves sintering and baking the enriched uranium oxide, and pressing it into coin-shaped ceramic pellets, which are stacked on top of each other and encased in the rods. The metal rods are made from zirconium alloys, because these are characterised by low neutron absorption.

[7] Energy intensities were deflated from 1967US$ to 1984US$ using inflation rates for the US 'Machinery and Equipment' sector provided by the US Bureau of Labour Statistics http://data.bls.gov/PDQ/servlet/SurveyOutputServlet.

[8] A Separative Work Unit is defined as $SWU = P\,V(x_p) + T\,V(x_t) - F\,V(x_f)$, where the value function is $V(x) = (1 - 2x)\ln[(1-x)/x]$, P, T and $F = P + T$ are the masses, and x_p, x_t and $x_f = P/F\,x_t + T/F\,x_f$ are the assays (concentrations) of product, tails and feed, respectively ([17] pp. 65-66).

[9] Extreme outliers (Orita 1995) were taken out of the average. A comparison of their figures for uranium milling with those from [19] shows that Storm van Leeuwen and Smith seem to directly add electrical and thermal energy, which is against recommended conventions [20]. They do give ratios of electrical to thermal energy, however for those references where a range of values is given, a correct reconstruction of electrical and thermal energy is impossible. We adopted their figures as they are stated as electrical energy, since the electrical energy outweighs thermal energy, in any case requiring only a small correction.

Some fuel rods contain a mixture of uranium oxide and plutonium oxide pellets, with the plutonium recovered and re-processed from spent, $^{235}_{92}\mathrm{U}$ -depleted fuel bundles. An assembly of such fuel rods is called a "mixed-oxide" (MOX) fuel bundle [32].

In high temperature reactors (HTR), the uranium fuel exists in form of small spheres, encased in layers of pyrolytic carbon and silica carbide. These fuel particles are then embedded in graphite fuel bundles [5].

Storm van Leeuwen and Smith [18] list eleven studies on the energy requirements of fuel fabrication (Table 3.6). The Australian Coal Association [24] states 52.7 MWh_{el} and 32.7 MWh_{th}. The figure used in the World Nuclear Association report [33] (last row in Table 3.6) is one of the highest in Storm van Leeuwen and Smith's list.

Electrical energy MWh_{el} / t U	Thermal energy GJ_{th}/ t U	Total energy requirement GJ_{th}/ t U
108	3	1,170
53	119	693
168	6,170	7,985
99	228	1,298
301	2,708	5,957
97	223	1,270
48	115	635
301	2,709	5,959
64	322	1,012
56	130	730
301	2,709	5,959

Table 3.6: Energy requirements for fuel fabrication. Figures were reconstructed from [18] by calculating the electrical energy e as $e = S / (1 + x)$, where x is the thermal to electrical energy ratio, and S is the specific energy given in [18], the thermal energy as $t = S - e$, and then the total energy requirement as $T = 3e + t$.

3.6 Reactor construction

In order to maintain a controlled nuclear chain reaction inside a reactor, it is necessary that of the 2-3 (fast) neutrons emitted from each fission event, on average 1 (slow) neutron causes a new fission event. This requires the following:

- fissile reactor fuel of sufficient concentration,
- a neutron moderator material to generate slow neutrons (water, heavy water, graphite, beryllium),
- near-absence of neutron-absorbing non-fissile materials, except for control rods (boron, cadmium).

Most commercial nuclear reactor types use enriched uranium as fuel, however there are types that can use $^{235}_{92}\mathrm{U}$ at its natural concentration. The fission of uranium or plutonium results in a range of particles that are emitted into the reactor core at high

velocities. These particles undergo multiple collisions with both fuel and moderator atoms, during which they lose their kinetic energy, and slow down.[10] This energy loss manifests itself in heat, thus raising the temperature of the reactor core. In order to keep this temperature below the melting point of core materials, while at the same time transferring the heat (via a heat exchanger) to the electricity-generating unit (steam turbine), a coolant has to be circulated through the core. In Light and Heavy Water Reactors (LWR, HWR), coolant and moderator are identical (water, H_2O, and heavy water, D_2O).[11] CO_2 and helium usually act as coolants in graphite-moderated reactors. Thus, nuclear reactors are characterised by a) their fuel, b) their moderator, and c) their coolant [34]. Table 3.7 lists the most common types.

Reactor type	Fuel (concen-tration)	Moderator	Coolant	Operating tempera-ture (°C)	Conver-sion rate	Comments
Pressurised Water (PWR)	UO_2 (3%)	H_2O	H_2O	320	0.55	Separate coolant and steam cycles; often used on military ships.
Boiling Water (BWR)	UO_2 (3%)	H_2O	H_2O	290	0.6	Identical coolant and steam cycles.
Heavy Water (HWR)	UO_2 (0.7%)	D_2O	D_2O	310	0.8	Needs high amount of moderator material. CANDU type, Canada.
Gas-cooled Graphite (GGR)	U (0.7%)	Graphite	CO2	410	0.8	
Advanced Gas-cooled Graphite (AGR)	UO_2 (2.6%)	Graphite	CO2	650	0.6	Magnox type, UK.
High-temperature (HTR)	UO_2 / ThO_2 (93%)	Graphite	Helium	> 750	0.7	Can generate high-temperature process heat. Used to burn off stocks of weapon-grade fuel.
Fast Breeder (FBR)	UO_2 / PuO_2 (18%)	-	Sodium (Na)	550	1.2	
Water-graphite (WGR)	UO_2 (1.8%)	Graphite	H_2O	280	0.6	RBMK type, Černobyl
Heat reactor (HR)	UO_2 (1.8-3%)	H_2O	H_2O	210	0.6	For district heating and water desalination. Large volume of coolant provides inherent safety.

Table 3.7: Common reactor types and their characteristics [3, 5].

Apart from using up fuel, every reactor also creates fuel, through breeding ${}^{238}_{92}\mathrm{U}$ and ${}^{232}_{90}\mathrm{Th}$ into ${}^{239}_{94}\mathrm{Pu}$, ${}^{241}_{94}\mathrm{Pu}$, and ${}^{233}_{92}\mathrm{U}$, which in turn are fissile. The conversion rate χ describes how many new fissile nuclei are bred for each fission event of the initial fissile fuel. Fast breeders have a conversion rate $\chi > 1$, meaning that they generate more fuel than they consume. Combined with the re-processing rate of spent fuel, the

[10] About 82% of the total kinetic energy of fission products is carried by the two nuclei resulting from the fission of the uranium or plutonium nucleus. Another 6% is carried by gamma particles, 5% by anti-neutrinos, and 3% each by electrons and neutrons. Except for the anti-neutrinos – which escape – most fission products (except those near the reactor wall) deposit their energy in the core.

[11] This feature brings about an intrinsic capacity for self-regulation: If the core temperature increases, the water density decreases, and with it decreases the ability to moderate, thus increasing neutron loss, and decreasing criticality.

conversion rate of reactors has a significant influence on the energy balance of nuclear energy systems.[12]

Estimates of the energy requirement for the construction of a nuclear power plant vary widely (Table 3.8). Hohenwarter and Heindler [35] explain differences in the overall energy requirement with economy-specific energy intensities. Based on our own survey, we conclude that the most significant factors influencing this energy requirement are a) the method employed for its calculation, and b) the type of reactor.

Reference	Year	Plant type	Energy requirement (GWh_{th} / GW_{el})	Method
[24]	2001	PWR	1,177	PA
[36]	2000	PWR	1,577	I/O
[26]	1978	LWR	2,160	I/O
[17]	1975	PWR	2,460	I/O
[17]	1975	BWR	2,465	I/O
[26]	1978	HTR	2,555	I/O
[37]	1975		2,607	
[17]	1975	LWR	2,664	I/O
[26]	1978	FBR	2,680	I/O
[38]	1975		3,162	
[39]	1992	PWR	3,180	I/O
[17]	1975	HTGR	3,195	I/O
[17]	1975	HTGR	3,418	I/O
[40]	1976	HWR	3,528	I/O
[41]	2000	PWR	3,763	I/O
[42]		LWR	3,800	AEI
[19]	1975	PWR	3,889	I/O
[19]	1975	PWR	3,942	I/O
[19]	1975	PWR	4,047	I/O
[19]	1975	PWR	4,100	I/O
cited in [35]	1977		4,100	
[29]	1975	PWR	4,285	AEI
[19]	1974	HTR	4,481	I/O
[19]	1973	HWR	4,625	I/O
[29]	1975	PWR	4,750	I/O
[29]	1975	BWR	4,761	I/O
[19]	1975	HWR	4,783	I/O
cited in [35]	1981		5,031	
[19]	1975	AGR	5,322	I/O
[12]	1976	HWR	6,623	I/O
[12]	1976	HWR	6,623	I/O
[19]	1975	AGR	7,082	I/O
cited in [35]	1984		7,220	
[43]	1975	FBR	7,796	I/O
[40]	1976	HWR	9,800	I/O
[3]	1983	PWR	12,286	AEI
[18]	2000	PWR	22,500	AEI
[18]	1967	PWR	29,722	AEI
[44]	1988	mix	74,832	AEI
[18]	1982	PWR	26,944	PA

Table 3.8: Energy requirements for the construction of a 1,000 MW nuclear power plant. AEI=Method of multiplying total cost with the national average energy intensity, I/O=Input-output-based hybrid analysis.

[12] The conversion rate χ is related to the *burn-up* β through $\chi = \beta \times 24\text{h/d} / (\rho_{iso}\ \eta_{235U}\ f) - 1$, where ρ_{iso} is the energy content of ^{235}U (24,500 $GWh_{th}/t^{235}U$), η_{235U} is the enrichment (%), and f is the fraction of ^{235}U burnt at re-loading (around $^2/_3$).

First, it is interesting to see that – with the exception of [29, 42] – employing the method of multiplying total cost with the national average energy intensity (AEI) yields an unusually high energy requirement. Second, advanced gas-cooled reactors, heavy water reactors, and fast breeders generally require more energy to be built than high-temperature gas-cooled reactors, and pressurised and boiling water reactors. This can be explained by the more complex design and additional components of the former reactor types. For example, Andseta et al [45] describe the greenhouse gas emissions from heavy water manufacturing in Canada.

Contrary to Storm van Leeuwen and Smith's assessment ([46] p. 259; [18] Chapter 3), we argue that multiplying the costs of the entire reactor with an economy-wide average energy or greenhouse gas intensity is not an appropriate method to assess the energy and greenhouse gas embodiments of a nuclear power plant. This is because:

a) National average energy and greenhouse gas intensities – calculated by dividing national energy consumption and greenhouse gas emissions by GDP – can only be applied to expenditures that are part of Gross National Expenditure (GNE). The costs of building a nuclear power plant are not part of GNE, they form part of intermediate demand.

b) A similar argument holds for applying input-output-based sectoral energy and greenhouse gas intensities, for example for the sector 'building' or 'construction'. These intensities refer only to final demand from these sectors, and not to intermediate demand. The costs of building a nuclear power plant are not part of the final demand of the construction sector, but part of its intermediate demand. In order to correctly assess energy and greenhouse gas emissions of parts of intermediate demand, the cost and revenue vectors for the application have to be inserted into the national input-output table, and a Leontief inverse has to be calculated for the augmented system (see [47-49] for more details).

c) A consequence of a) and b) is that if input-output energy and greenhouse gas intensities calculated using the conventional Leontief inverse (see [50]) are used for enumerating the direct and indirect effects associated with a producing entity, double-counting occurs (compare Section 2.9; for further details see [51, 52]). This double-counting is in the order of the ratio of the respective sector's gross output and its final demand. In order to avoid double-counting, life-cycle contributions have to split amongst supply-chain stages. The energy and greenhouse gas intensities resulting from an adjusted Leontief inverse are lower than conventional intensities.

d) Averages of energy and greenhouse gas intensities for one particular sector (for example 'building' or 'construction') may not be representative for particular application, because of differences in the input mix between the sector and the application. There is ample evidence for the so-called *aggregation error* associated with this procedure: In order to calculate this type of error, Lenzen [53] lists studies that demonstrate the variation of various intensities at the plant/establishment level with regard to the sector average. Nuclear power plants cannot be assumed *a priori* to be a representative product of a input-output 'construction' sector, because there is

evidence that points to particularly high proportion of planning, administrative and regulatory costs, which do not attract high energy intensities [26, 33, 54]. As Bullard et al ([55] p. 283) point out, "*when used to approximate the energy intensity of a particular item such as a power plant, this* [AEI] *coefficient has an extremely large uncertainty*…". The fact that some I/O and AEI assessments [29, 42] coincide is hence coincidence. There is no general rule that suggests a constant factor to be applied in order to convert between AEI and I/O methods, as suggested by Storm van Leeuwen and Smith.

Regarding argument d), Wagner ([26] p. 52-53) demonstrates an appropriate use of the input-output technique by first breaking up the monetary reactor cost into components, and then multiplying these components with corresponding input-output multipliers (compare [47, 55]). Both plant construction and dismantling routinely involves large amounts of cost associated with leasing of land, court cases, approval prodecures, licensing, delays, fees, taxes, insurance, interest, and remote-controlled dismantling [26, 56-58]. This more detailed hybrid input-output technique ensures that these costs are not given high energy and greenhouse gas intensities. Whereas Storm van Leeuwen and Smith (AEI) arrive at values around 25,000 GWh, Wagner [26] concludes with 2,160 GWh_{th} for a 1000 MW light water reactor. Other input-output analyses yield values up to 4,100 GWh_{th} (Table 3.8). These assessments may still overestimate the energy and greenhouse gas embodiments because of the remaining issues a) to c).

The process analysis by Storm van Leeuwen and Smith (last row in Table 3.8) can also be subjected to further query: The authors state a total mass of 516 kt, which equates to 97 PJ in their analysis, thus yielding a specific energy requirement of the reactor materials of 188 MJ/kg. This figure is higher than most literature values for materials used in reactors, with the exception of aluminium (Table 3.9).

Reference	[39]	[40]	[59-61]	[41]	[36]	[62]	[63]
Reinforced steel	27.8	39.6	40	40	40	58.5	29.2
Stainless steel	71.0	111.6		56	53		
Concrete		1.71	1.4	1.5	1.4		1.0
Copper	33.2	86.4		112	131	123	51.8
Aluminium	252.1		120	140	208	262	243
Cement	4.7	8.28				6.2	3.9

Table 3.9: Specific energy requirements (MJ/kg) for materials from selected studies on the construction of nuclear power plants.

There are a number of energy analyses of reactor construction that proceed similarly to Storm van Leeuwen and Smith's process analysis, i.e. via a material inventory (Table 3.10). While Storm van Leeuwen and Smith's inventory is realistic, none of these studies yield energy embodiments that are anywhere near their 97 PJ or 27,000 GWh.

Refe-rence	Reinforced steel	Stainless steel	Concrete / cement	Copper	Alumi-nium	Total	
[36]	34	2	180	0.7	0.02	216	'000 t
	377	29	70	27	1	504	GWh
[28]	46	20	480	1.4	0.2	548	'000 t
	506	300	187	51	12	1055	GWh
[40]	40	10	250	2.4	0.2	303	'000 t
	440	310	119	58	12	938	GWh
[64]	53	3	70	0.7	0.1	127	'000 t
	406	58	93	7	6	569	GWh
[39]	54	3	98	1.5	0.1	157	'000 t
	416	62	129	14	6	626	GWh
[24]	51.8		659	2.7	0.09	707	'000 t
	842		311	98	7	1257	GWh
[27] [a]	61.2		372	1.5	0.2	435	'000 t
	994		177	54	15	1239	GWh
[18] [a]	40	25	450	1.2	0.2	516	'000 t
	650	775	214	44	15	1697	GWh

Table 3.10: Reactor inventory ('000 t) and energy embodiment. [a]: Maximum of energy intensities in Table 3.9 applied to material inventory.

All process analyses in Table 3.10 yield markedly lower values than input-output analyses in Table 3.8, due to the truncation error inherent in the system boundary choice [41, 47, 53, 59, 65, 66].

Tyner et al [44] emphasise the fact that a sizeable proportion of expenses in an energy supply system are capital and other overhead costs (45% for the US [44], 36% for Australia [67]). The energy requirements of these costs are often not covered in process analyses, or simplified input-output analyses.[13]

3.7 Reactor operation

As with reactor construction, estimates of the energy requirement for the operation of a nuclear power plant vary widely (Table 3.11). Based on our own survey, we could not conclusively establish any clear determinants for these figures.

[13] Tyner et al [44] go on to explain energy feedback loops that arise out of "indirect purchases of physical goods", that is the personal expenses of people involved in the design and construction of a power plant, and in fabricating the components. These authors refer to what the input-output literature calls a *semi-closed system*. The energy intensities resulting from such a system are referred to as *type-II (energy) multipliers*. They are considerably higher than conventional type-I multipliers, since they include earning-spending loops. Accounting conventions for energy analysis explicitly exclude energy arising from such loops [20, 68], and these conventions are followed in this report.

Reference	Year	Plant type	Energy requirement (GWh_{th} / GW_{el} /y)	Method
[9]	1976	HWR	38	I/O
[9]	1976	HWR	44	I/O
[15]	1975	HWR	66	I/O
[1]	1983	PWR	79	AEI
[29]	1992	PWR	112	I/O
[15]	1973	HWR	116	I/O
[13]	1975	BWR	223	I/O
[13]	1975	HTR	229	I/O
[13]	1975	PWR	230	I/O
[13]	1975	PWR	231	I/O
[13]	1975	PWR	231	I/O
[13]	1975	PWR	235	I/O
[13]	1975	HTR	237	I/O
[13]	1975	PWR	242	I/O
[13]	1975	HWR	473	I/O
[44]	1988		666	AEI
[18]	2005	PWR	889	AEI

Table 3.11: Energy requirements (GWh_{th} / year) for the operation of a 1,000 MW nuclear power plant. AEI=Method of multiplying total cost with the national average energy intensity, I/O=Input-output-based hybrid analysis.

For the operation of a LWR and HWR, Rotty et al [17] detail inputs of diesel, chemicals, hardware, and maintenance of 8.5 GWh_{el} of electricity and 80 GWh_{th} of thermal energy annually. In addition, HWR reactors require in the order of 7 GWh_{el} of electricity and 40 GWh_{th} of thermal energy annually for their heavy water moderator ([17] p. 85, [45]). This input list probably omits a substantial amount of overhead costs, repair and replacement of components, and changes to plants due to regulatory measures. Two studies apply average energy intensities to the entire financial operating budget of the nuclear power plant [18, 69]. However, a closer examination of total operating data in [69] yields however that about 40% of these costs are wages and pensions, a further 30% are insurance and administration, and 15% each are technical services and materials. Excluding wages and pensions, average operating, maintenance and capital expenditures are about 120 1990US$/$kW_{el}$/y [69], which agrees with a figure of 100 M$/$GW_{el}$/y quoted by Storm van Leeuwen and Smith [18]. Converting the cost breakdown in [69] with energy intensities between 10 and 50 MJ/$ yields an energy requirement of about 300 GWh_{th}/y for a 1000 MW reactor, which is close to the highest values in Table 3.11. For these reasons, and reasons stated in the previous Section, we will discard analyses based on the AEI method.

3.8 Decommissioning

At the end of its life, a typical nuclear reactor poses the task of disposing of about 10,000 tonnes of medium- to high-level radioactive waste, some 10,000 tonnes of low- to medium-level radioactive waste, and some 100,000 tonnes of non-active materials [5, 70]. Radioactive materials have to be disposed of just as tailings, tails, spent fuel and fission products, depending on their radioactivity levels (see 3.10 and 3.11). Most of the radioactivity (99%, [71]) is contained in the high-level waste. Table 3.12 gives a comparative overview of radioactivity levels.

	Radioactivity (Bq / m^3)
Fuel during reactor operation	5×10^{17}
High-level waste	$> 3.7\times10^{14}$ ($> 10^4$ Ci/m^3)
Medium-level waste	$3.7 – 37\times10^{13}$ ($10^3 – 10^4$ Ci/m^3)
Plutonium	5×10^{13}
Low-level waste	$< 3.7\times10^{13}$ ($< 10^3$ Ci/m^3)
Uranium (natural)	5×10^8
People (natural)	10^5
Granite (natural)	10^5
Water (natural)	$10^2 – 10^4$
Air (natural)	$10 – 10^2$

Table 3.12: Comparative overview of radioactivity levels [5]. Radioactivity is defined by the number of decay events per unit of time. Its measures are the Becquerel (Bq; 1 Bq = 1 decay per second) and the Curie (Ci; 1 Ci = 3.7×10^{10} Bq).

Heinloth [5] gives a crude estimates for the cost of dismantling a nuclear reactor as typically in the order of ¼ of the cost for its construction. A more detailed assessment is Komorowski and Meuresch's [54] account of cost for the decommissioning of reactors (both research and commercial types), waste repositories, and reprocessing plants. These authors state the example of the Niederaichbach plant as the first completely disassembled nuclear reactor in Europe [57, 72, 73]. They note, however, that their cost figures may not be representative because

a) the highly variable durations and delays of the legal procedures preceding the decommissioning incurred variable idling costs (see also [73]), and
b) the decommissioning of German nuclear installations in the 1990s generally occurred not because their end of life was reached, but because of a change in the political consensus at the time.

The German data are highly variable, but give an indication that large commercial reactors attract lower decommissioning cost (about 10% of construction cost) than small, experimental reactors (around 100%, compare also [74] pp. 16-17). The International Atomic Energy Association estimates decommissioning cost of commercial facilities to be in the order of 250-500 million US$ [58, 74]. Even though the decommissioning of a single enrichment or conversion plant may cost more than that of a power plant, the latter dominate decommissioning cost for the whole fuel cycle ([74] p. 24). In their energy analysis, the World Nuclear Association [33] provides five figures for decommissioning of existing nuclear power plants, ranging

between 4.3 PJ and 6.2 PJ.[14] Assuming energy requirements of 4,100 GWhth ≈ 15 PJ, decommissioning represents about 35% of construction.

Plant	Construction cost (inflated)	Planned decommissioning cost	Idling cost since ceasing operation	Total decommissioning cost	
Commercial HTR Hamm-Uentrop THTR-300	6,997	642		642	(9%)
Commercial FBR Kalkar SNR-300	10,033	239	26	265	(3%)
Small reactor Niederaichbach	444	279	147	426	(96%)
Small reactor Karlstein	229	98	101	199	(87%)
Experimental reactor Karlsruhe	1,019	529	86	615	(60%)
Multi-purpose reactor Karlsruhe	404	439	86	525	(130%)
Research reactor Karlsruhe	174	245	63	308	(177%)
Experimental reactor Jülich	219	358	147	505	(231%)
Reprocessing plant Karlsruhe	458	3,354	272	3,626	(792%)
Repository shaft Asse	380	234	18	252	(66%)

Table 3.13: Decommissioning cost for German nuclear installations (10^6 DM, after [54]).

In contrast with these estimates, Storm van Leeuwen and Smith [18, 46] argue for safeguarding periods ranging from decades to a century before the actual dismantling of the reactor. For the decommissioning stage these authors distinguish two options. In the "environmentally responsible" option, which includes safeguarding, clean-up, demolition, dismantling, packaging and permanent disposal, costs of 200% the construction costs are incurred. In the "*après nous le déluge*" option, the plant is safeguarded but not disposed of at all, incurring 100% of construction costs. These costs are multiplied – as with construction and operation – with the national average energy intensity. The critique about the AEI method stated in Section 3.6 applies to this stage as well.

3.9 Fuel reprocessing

In typical light water reactors, fuel bundles are removed from operation once the concentration of neutron-absorbing fission products is high enough to adversely affect the reactor's criticality. At this point, the concentration of ${}^{235}_{92}\mathrm{U}$ has decreased to below 1%. Typically, a 1000 MW nuclear power plant produces about 30 tonnes of spent fuel per year, which can be either disposed of as waste, or re-processed. If re-processed, the spent fuel bundles are cut, and the fuel is dissolved and separated into its constituents, which are 95% ${}^{238}_{92}\mathrm{U}$, 1% ${}^{235}_{92}\mathrm{U}$, about 1-2% plutonium isotopes, 2-3% radioactive fission products (${}^{85}\mathrm{Kr}$, ${}^{129}\mathrm{I}$, ${}^{3}_{1}\mathrm{H}$, etc), and less than 0.1% trans-uranic elements. Uranium and plutonium are precipitated from the solution, and fabricated

[14] Bruce A 5.2 PJ, Bruce B 4.3 PJ, Darlington 4.5 PJ, Pickering A 5.7 PJ, Pickering B 6.2 PJ [33].

into new fuel assemblies [3, 5]. The separation of isotopes during re-processing is carried out using the centrifuge method (see Section 3.4). Starting from spent fuel, $^{235}_{92}U$ has to be enriched to a higher degree, compared with conventional enrichment of natural uranium, because of the presence of $^{236}_{92}U$ impurities that act as a neutron absorber.

Re-processing reduces both the requirement for natural uranium as the volume of waste to be disposed. Rotty et al [17] report values of about 30 GWh_{el} of electricity and 150 GWh_{th} of thermal energy annually for a 1000 MW light water reactor.

3.10 Nuclear waste storage

A typical 1000 MW nuclear power plant produces about 25 tonnes of spent fuel annually [5], which emits radiation principally from fission fragments (for example krypton ^{85}Kr, iodine ^{129}I, and tritium $^{3}_{1}H$). This spent fuel is transferred into storage ponds, and either re-processed or prepared for permanent disposal. Waste from spent fuels and re-processing is classified as high-level radioactive ($> 10^4$ Ci m^{-3}). However, most of the fission fragments are short-lived, so that before transferring this type of waste to central disposal facilities, they are – except for ^{85}Kr - encased in either glass (vitrified), concrete and/or metal, and kept in ponds in the vicinity of the reactor for a time sufficient to allow their concentration (and radioactivity) to subside to less than 1% of its original magnitude [3, 75].

Rotty et al [17] state that most of the energy requirement in this stage is for process materials such as concrete for encasing and steel for storage canisters. However, the scope of their life-cycle assessment, and in particular whether it includes the construction of final repositories, is unclear. They report values of about 167 MWh_{el} of electricity and 1,800 MWh_{th} of thermal energy annually for storing the waste from a 1000 MW light water reactor. In Rotty's analysis, most of this energy is expended for ongoing operation rather than for the construction of the disposal facilities.

Corresponding figures by the Australian Coal Association [24] are substantially higher at 1997 MWh_{el} of electricity and 14,733 MWh_{th} of thermal energy. This study only deals with the storage of high-level active spent fuel which, for a typical 1000 MW LWR, is about 25 tonnes annually, yielding specific energy requirements of about 80 MWh_{el} / t fuel and 600 MWh_{th} / t fuel. White and Kulcinski's [36] figure is comparable at 172 TJ_{th} per GWy and, if applied only to operational waste at the power plant, corresponds to about 400 MWh_{th} per tonne of radioactive material. The Australian Coal Association states storage to represent about 4% of a diffusion-enriched nuclear cycle [24]. White and Kulcinski's figure is about 9% for a centrifuge-enriched cycle [36].

By far the highest of all reported energy requirements for waste storage are calculated from cost data (151-1,340 2000$/kg heavy metals) by Storm van Leeuwen and Smith [18]. Multiplying by the national average energy intensity yields 440 MWh_{el} / t fuel and 2,200 MWh_{th} / t fuel. Hence, the critique about the AEI method stated in Section 3.6 applies to this stage as well.

3.11 Nuclear waste disposal

In addition to the decommissioning of the plant, there are a number of stages in the nuclear fuel cycle that produce radioactive waste [1, 74, 76]. The first one is the mining and milling stage, where the remainder of the ore after the extraction of uranium (the "tailings") have to be kept away from the environment. This is often done in specially engineered mined out pits [10, 77, 78]. Waste from mining and milling is classified as low-level radioactive ($< 10^3$ Ci m^{-3}).

The second stage to produce radioactive waste is enrichment. After the concentration of $^{235}_{92}U$ from 0.7% to above 3% (typical for light water reactors), the depleted stream (the "tails") is discarded. Waste from enrichment contains less $^{235}_{92}U$ than natural uranium. Small quantities of this waste are used for radiation shielding and for mixed-oxide (MOX) fuel production [10].

The third stage is the operation of nuclear reactors, where structural components such as fuel rod tubes become contaminated. Typically, a 1000 MW nuclear power plants produces about 13 tonnes of contaminated structural material annually [5]. Waste from operation is classified as medium-level radioactive ($10^3 – 10^4$ Ci m^{-3}).

Fourth, spent fuel needs to be disposed of after being kept in ponds in the vicinity of the reactor for a time sufficient to allow their concentration (and radioactivity) to subside.

Fifth, re-processing requires conversion and enrichment, which in turn leaves depleted uranium as a waste product. This can be stored either as UF_6, or as U_3O_8, with the HF being recycled [22].

Finally, at the end of the power plant's life, about 10,000 tonnes of medium- to high-level radioactive waste and some 10,000 tonnes of low- to medium-level radioactive waste have to be disposed of.

At present, low- and medium-level radioactive wastes are routinely disposed of in near-surface strata such as abandoned mines. High-level wastes are proposed to be disposed of in deep geological formations such as salt domes or granite bodies, which are required to exhibit a lack of contact with ground water, tectonic stability, sufficient heat conductivity, and low permeability for radionuclides [76]. It is impossible to completely avoid the solution of radionuclides in circulating ground water, because a) every rock formation is in principle water-permeable, and b) every container material is in principle water-soluble or corrodible. However, it is also not necessary to absolutely hermetically seal radioactive wastes. Natural uranium and thorium is naturally dissolved into the ground water at some small rate, and it is sufficient that the projected rate of release does not significantly exceed the natural rate [5].

The disposal stage is perhaps to most difficult to analyse of all stages, because there are not many comprehensive studies on commercially operating nuclear waste

facilities. The Swedish nuclear plant operator Vattenfall keeps low-level waste inside the power plant, or buried at an on-site facility. Intermediate-level waste (such as contaminated reactor components) is transferred to a final repository (SFR Forsmark) consisting of vaults 50 metres below the sea floor in 5 mere deep water. The intermediate-level waste deposited there requires in the order of 500 years to decay to background activity. High-level waste is kept for 30 years a Sweden's central interim storage facility for spent nuclear fuel (CLAB Oskarshamn), consisting of vaults located 25-30 metres below ground. Spent fuel is stored there in deep pools of water in order to enable cooling to a temperature sufficiently low to enable final disposal. After 30 years, the waste is planned to be encapsulated in concrete or sealed in copper canisters, and placed in a deep repository (at approximately 500 metres depth). As of 2004, the location of this repository was not yet determined [1].

Final waste disposal has significant international aspects [79]. As Pasztor [80] points out, "*there has been considerable discussion in the literature about the desirability and the possibility of an international repository for high-level radioactive wastes. The rationale behind such a concept is partly technical, partly political. On the one hand, some of the most stable geological formations of the world are not where population densities are high (or where nuclear power is intensively used), but often in remote areas* […]. *Technically, the location of large repositories in such areas would be ideal. Such solutions are particularly favoured by small nations, whose nuclear programmes are too small for independent work on a repository to be economical.*"

There are a number of studies that – in addition to storage – deal more comprehensively with waste management, and include longer-term disposal stages. These studies conclude that overall waste management is responsible for 5-9% [28], 14% [2], and 13% [81]of greenhouse gas emissions, respectively. Unfortunately these studies do not reveal any energy budgets, so that a transfer to Australian conditions is not readily possible. The Environmental Product Declaration for Torness drew on input from a reference scenario for waste management [82]. Applying maximum energy intensities as in Table 3.9 to the data for this scenario yields energy embodiments of about 47 and 380 GWh_{th}, respectively (Table 3.14).

ILW/LLW facility	000 t	GWh	HLW facility	000 t	GWh	MJ/kg
Reinforced steel				5.2	84.7	58.5
Stainless steel	0.5	16.6				111.6
Concrete	24.1	11.4		372.6	177.3	1.7
Copper				3.2	117.7	131.0
Cement	8.3	19.1				8.3
Totals	32.9	47.1		381.0	379.8	

Table 3.14: Material and energy inputs into the construction of ILW/LLW and HLW waste repositories.

Including 3 MW of electricity input over 40 years ([82] p. 10) yields the breakdown in Table 3.15.

	High-level waste	Intermediate-level waste	Low-level waste
Mass (tonnes)	3192	10138	32923
Construction energy (GWh_{th})	380	47	
Electricity (GWh_{el})	1051	1051	
Total energy (GWh_{th})	3533	3201	
Construction energy per tonne (MWh_{th})	119	1	
Electricity per tonne (MWh_{el})	329	24	
Total energy per tonne (MWh_{th})	1107	74	

Table 3.15: Total deposited waste mass, and energy requirements of ILW/LLW and HLW waste management.

By far the highest of all reported energy requirements for high-level waste disposal are calculated from cost data (monetary values not stated) by Storm van Leeuwen and Smith [18]. Applying the national average energy intensity method yields 3,500 MWh_{th} per tonne of HLW. As with waste storage, the critique about the AEI method stated in Section 3.6 applies to this stage as well.

Storm van Leeuwen and Smith [18] distinguish two kinds of intermediate- and low-level waste: operational wastes (conditioning and disposal) and enrichment tails of depleted uranium (re-conversion, conditioning and disposal). Depleted uranium forms the bulk of these ILW/LLW waste products, with an energy requirement of about 470 MWh_{th} per tonne. Most of this energy requirement is for re-conversion of the UF_6, and the per-tonne coefficient derived from data for conversion (see Section 3.3). In comparison, the Environmental Product Declaration for Torness [82] yields less than 100 MWh_{th} per tonne of general ILW/LLW waste (Table 3.15).

Finally, Storm van Leeuwen and Smith [18] quantify the energy requirements for restoring the mine site to "green fields" conditions, which primarily involves neutralising and immobilising the mine tailings. Immobilisation is assumed to be achieved by sandwiching the mine tailings between bentonite layers. The authors note that this process is based on their own hypothetical model, and that in reality mine tailings are not treated in this manner. They state specific energy requirements of 1.25 MWh_{th} per tonne of tailings.

3.12 Transport

There is a large body of literature on energy and greenhouse gas intensities of transport modes [83-94], and a number of reports deal with Australian transport [95-105]. In this report, we rely on a comparative review of all Australian studies – process and input-output – and data sources [106, 107] for calculating the energy and greenhouse gas intensities of transport. Characteristics of transport modes are usually reported as either monetary intensities (MJ and kg CO_2-e per unit of transport revenue / cost in $), or as physical intensities (MJ and kg CO_2-e per unit of transport task in net-tonne kilometres, ntkm). Table 3.16 presents a comparison between energy intensities obtained from input-output analysis and process analysis of the Australian freight system [107].

Freight mode	Energy intensity, monetary units, IO analysis (MJ/A$)	× Revenue = (A¢/ntkm)	Energy intensity, physical units, IO analysis (MJ/ntkm)	Energy intensity, physical units, hybrid analysis (MJ/ntkm)
Truck	20.5±1.4	11.8	2.43±0.2	2.34
Train	14.8±2.5	4.1	0.61±0.1	0.88
Ship	43.8±6.4	0.6	0.26±0.1	0.40

Table 3.16: Comparison of energy intensities of various Australian freight modes obtained from input-output and from hybrid energy analysis.

The first column contains energy intensities in MJ/A$ from input-output analysis, taken from [107]. These were converted into units of MJ/ntkm (third column) using revenue figures (second column, [106]). This conversion effects a re-ranking of modes in the freight sector, with shipping becoming the most energy-efficient mode in terms of ntkm. For road transport, input-output-based and hybrid intensities are in reasonable agreement. However, this is not the case for sea and rail freight transport.

These discrepancies are due to the fact that monetary output data for the water transport industries is defined as revenue derived in Australia from services provided by national and international carriers, while energy data describe fuel taken up within Australian territory. Since these definitions are not equivalent, the input-output-based energy intensities for these industries show deviations from those obtained by hybrid analysis. The hybrid analysis of railway freight covers only government rail, while the input-output analysis covers private and government-run operations. Since private systems (mostly hauling iron ores at various mining sites) are more energy-efficient than government systems, the energy intensity from input-output analysis is lower than the one from hybrid analysis. In this report, we will therefore use the following intensities:

Freight mode	Operating cost (A¢/ntkm)	Energy intensity (MJ/ntkm)			GHG intensity (kg CO_2-e/ntkm)		
		fuel	operation	total	fuel	operation	total
Coastal shipping	0.6	0.3	0.1	0.4	0.02	0.01	0.03
Government rail	4.1	0.5	0.4	0.9	0.04	0.05	0.08
All rail (IO analysis)	4.1			0.61			0.054
Articulated trucks	5.4	1.4	0.3	1.7	0.11	0.03	0.13
Rigid trucks	39.4	3.5	1.1	4.6	0.26	0.11	0.37
Light commercial vehicles	707.5	32.0	16.8	48.8	2.24	1.66	3.9
International air	42.9	24.1	5.4	29.5	1.76	0.55	2.3
Domestic air	99.8	34.1	19.5	53.6	2.5	1.8	4.3
Regional air	355.7	48.1	64.2	112.3	3.5	6.1	9.6
Charter business aviation	713.1	96.7	100.7	197.5	7.0	10.0	17.0

Table 3.17: Energy and greenhouse gas intensities for freight transport [106, 107].

3.13 Total energy and greenhouse gas emissions

A large number of studies exist on the energy balance and greenhouse gas emissions associated with the nuclear fuel cycle, or components thereof. A sizeable portion of these however was rather inaccessible to the authors for further analysis, because of a number of reasons, such as

- older reports are out of print and unavailable in electronic format,
- some reports are written in Japanese (the authors could evaluate only English and German reports), and
- many reports do not reveal critical details and assumptions.

Amongst those reports not evaluated for some of the above reasons is a 2006 Japanese study by Tokimatsu et al [108] evaluating the CO_2 consequences of the Japanese economy under various nuclear scenarios, ranging from complete phase-out to scenarios involving new-generation fast breeder reactors. Similarly, the 2006 evaluation by Fthenakis et al [109] for the entire US power system appears very thorough but does not reveal a lot of detail, thus warranting further investigation of the data sources. Finally, many of the older studies [12, 26, 40, 43, 44, 110] focus on the dynamic transition of the energy supply system of a whole economy. Such an analysis – involving a mix of power supply options – is more realistic and informative than a static life-cycle assessment, but was outside the scope of this work.

The most detailed of all studies are probably the early study of US reactor types by Rotty et al [17], Storm van Leeuwen and Smith's general analysis [18], and the Environmental Product Declaration by Sweden's Vattenfall [1, 2]. Rotty et al's study is detailed in listing all energy requirements, and in that it includes auxiliary services and upstream energy through input-output analysis. Storm van Leeuwen and Smith's analysis covers all stages of the nuclear fuel cycle, however it has been the subject of considerable controversy (see Section 3.14). Vattenfall's study contains a detailed life-cycle material inventory and transport tasks, however it omits the energy and

greenhouse gas impacts of many upstream contributions as well as auxiliary services such as insurance etc.[15]

As expected, results of greenhouse gas analyses vary more than those of energy balances, because of the additional influence of the fuel mix, or greenhouse gas intensity of the background economy. This is amply demonstrated in Fthenakis' study of the US [109], Andseta et al's comparative study of Canada [45], Lewin's assessment of nuclear plants in the German grid [111], and the report by Dones et al on European countries [28, 112, 113].

Table 3.18 summarises all studies examined in this review. The most important plant parameters are given, such as technology vintage (year), assumed lifetime and load factor, uranium concentrations in ores, fuel and enrichment tails, and the conversion rate of the whole fuel cycle. The column 'Stages covered' uses acronyms for the fuel cycle stages covered in this Section (see Table caption), followed by bracketed numbers representing the percentage of the respective stage's requirement in the entire energy or greenhouse gas balance (compare with an overview by van der Vate [114]). All available information was extracted from the literature.

[15] Vatenfall's EPD document ([2] p. 12) states systematic underestimations to be less than 7.5%. Given the substantial omissions of upstream energy and greenhouse gas requirements as well as service inputs, the truncation error is probably higher than 20% (compare [53]).

Reference	Year of study	Reactor type	Power rating (MW_{el})	Life time (y)	Load factor (%)	Ore grade (‰)	Enrichment technology	% tails	% ^{235}U in fuel	Conversion rate	Energy intensity $1 / R_1$ $\left(\frac{kWh_{th}}{kWh_{el}}\right)$	Analysis type	Stages covered (% of life cycle)	Remarks
[19]	1973	HWR	1000	25	60	3.1	Df		2.1		0.22	I/O	M(2)L(2)V(2)**E(69)**F(1)C(16)O(10)	SGHWR [115]
[19]	1974	HTR	1000	25	60	3.1	Df		6.5		0.31	I/O	M(1)L(1)V(1)**E(85)**F(0)C(11)O(0)	TNPG design
[43]	1975	FBR	1000	25	100	-	-	-	18.0	1.0	0.04	I/O	M(0)L(0)V(0)EFOR(11)**C(89)**	Data in [40]
[19]	1975	HWR	1000	25	60	3.1	-		0.72		0.07	I/O	M(6)L(6)V(6)E(0)F(12)**C(52)**O(18)	Pickering CANDU
[19]	1975	AGR	1000	25	60	3.1	-	-	0.72		0.11	I/O	M(10)L(11)V(10)E(0)F(20)**C(49)**O(0)	Oldbury A Magnox
[17]	1975	HWR	1000	30	75	1.76	-	-	0.72		0.12	I/O	M(4)L(4)V(0)E(0)F(29)**CO(60)**R(3)SW(0)T(1)	CANDU
[17]	1975	PWR	1000	30	75	1.76	Df	0.3	3.2		0.17	I/O	M(2)L(3)V(5)**E(63)**F(5)CO(21)R(0)SW(0)T(0)	Pu rec.
[17]	1975	HTR	1000	30	75	1.76	Df	0.3	93.2	0.66	0.18	I/O	M(2)L(2)V(4)**E(70)**F(2)CO(20)R(0)SW(0)T(0)	^{233}U rec.
[17]	1975	BWR	1000	30	75	1.76	Df	0.3	2.73		0.20	I/O	M(3)L(3)V(6)**E(66)**F(4)CO(17)R(0)SW(0)T(0)	no rec.
[19]	1975	PWR	1000	25	60	3.1	Df		2.7		0.20	I/O	M(2)L(2)V(2)**E(79)**F(1)C(15)O(0)	Shearon Harris
[17]	1975	PWR	1000	30	75	1.76	Df	0.3	3.2		0.22	I/O	M(3)L(3)V(6)**E(68)**F(3)CO(16)R(0)SW(0)T(0)	no rec.
[19]	1975	PWR	1000	25	60	3.1	Df		2.6		0.22	I/O	M(2)L(2)V(2)**E(81)**F(1)C(14)O(0)	Maine Yankee
[17]	1975	PWR	1000	30	75	1.76	Df	0.2	3.2		0.25	I/O	M(2)L(2)V(4)**E(74)**F(3)CO(14)R(0)SW(0)T(0)	no rec.
[19]	1975	PWR	1000	25	60	3.1	Df		3.35		0.26	I/O	M(1)L(2)V(1)**E(83)**F(0)C(12)O(0)	Jos M. Farley
[19]	1975	AGR	1000	25	60	3.1	Df		2.45		0.27	I/O	M(2)L(2)V(2)**E(80)**F(1)C(15)O(0)	Hunterston B
[17]	1975	HTR	1000	30	75	0.06	Df	0.3	93.2	0.66	0.29	I/O	M(10)**L(33)**V(2)E(42)F(1)CO(12)R(0)SW(0)T(0)	^{233}U rec.
[17]	1975	PWR	1000	30	75	0.06	Df	0.3	3.2		0.32	I/O	M(12)**L(39)**V(3)E(33)F(3)CO(11)R(0)SW(0)T(0)	Pu rec.
[19]	1975	PWR	1000	25	60	3.1	Df		3.3		0.37	I/O	M(1)L(2)V(2)**E(87)**F(0)C(8)O(0)	Haddam Neck
[17]	1975	PWR	1000	30	75	0.06	Df	0.3	3.2		0.46	I/O	M(13)**L(43)**V(3)E(32)F(2)CO(8)R(0)SW(0)T(0)	no rec.
[12]	1976	HWR	1000	25	60	3.0	Df	0.25	2.1		0.24	I/O	M(2)L(2)V(2)**E(69)**F(1)C(21)O(3)	CANDU
[12]	1976	HWR	1000	25	60	0.07	Df	0.25	2.1		0.28	I/O	M(9)**L(39)**V(1)E(29)F(0)C(18)O(3)	CANDU
[26]	1978	FBR	1300	25	79.9	-	-	-			0.019	I/O	FO(19)**C(81)**	
[26]	1978	LWR	1300	25	79.9	2	Ce				0.04	I/O	**MLVEFO(71)**C(29)	
[26]	1978	HTR	1300	25	79.9	2	Ce				0.04	I/O	**MLVEFO(66)**C(34)	
[26]	1978	HTR	1300	25	79.9	0.2	Ce				0.13	I/O	**MLVEFO(89)**C(11)	
[26]	1978	LWR	1300	25	79.9	0.2	Ce				0.16	I/O	**MLVEFO(92)**C(8)	
[26]	1978	LWR	1300	25	79.9	2	Df				0.18	I/O	**MLVEFO(93)**C(7)	
[26]	1978	HTR	1300	25	79.9	2	Df				0.21	I/O	**MLVEFO(93)**C(7)	

[26]	1978	LWR	1300	25	79.9	0.2	Df				0.29	I/O	**MLVEFO(96)**C(4)	
[26]	1978	HTR	1300	25	79.9	0.2	Df				0.30	I/O	**MLVEFO(95)**C(5)	
[3]	1983	PWR	1000	25	75	≈ 3	Ce		3.0	0.55	0.11	AEI	MLV(12)EF(7)**C(68)**O(11)S(1)W(1)	Biblis A [c]
[44]	1988		1000	30	50						0.85 [d]	AEI	MLVEF(12)**C(67)**OT(18)DSW(3)	
[39]	1992	PWR	1000	30	75		Df				0.19	I/O	M(3)L(3)V(7)**E(66)**F(3)C(8)O(9)R(0)S(0)T(0)	
[116]	1996	FBR	1000	30	75	-	-	-			0.009	I/O		
[117]	1999	BWR	1000	30	75		Ce			30 [b]	0.036	I/O	ML(1)V(10)E(22)F(2)**O(33)**R(22)D(0)SW(10)	Pu recycle
[117]	1999	BWR	1000	30	75		Df			30 [b]	0.10	I/O	ML(1)V(4)**E(81)**F(1)O(11)D(0)SW(2)	
[41]	2000	PWR	1000	40	86.8						0.006	PA	COD(100)	Doel 3/4
[41]	2000	PWR	1000	40	86.8						0.018	I/O	COD(100)	Doel 3/4
[36]	2000	PWR	1000	40	75		Ce		3.0		0.06	I/O	M(5)**LVEF(63)**C(10)O(12)D(1)SW(9)T(0)	
[24]	2001	PWR	1000	30	80	0.2	Df		3.2		0.14	PA	**MLE(86)**V(6)C(4)S(4)	U from Ranger mine, US grid
[28]	2004	PWR	1000	40	81.4	2.0	Df	0.26	3.8	42.8 [b]	0.03	PA		MOX fuel
[28]	2004	BWR	1000	40	81.4	2.0	76% Ce	0.26	4.0	48 [b]	0.045	PA		MOX fuel
[18]	2005	PWR	1000	24	82	1.5	70% Ce	0.2	4.2	46 [b]	0.66 [a]	AEI	ML(3)V(2)E(13)F(1)**C(24)**O(15)**D(24)**S(9)W(11)	
[18]	2005	PWR	1000	24	82	0.1	70% Ce	0.2	4.2	46 [b]	1.63 [a]	AEI	ML(22)V(1)E(5)F(0)C(10)O(6)D(10)S(4)**W(44)**	
[29]	1975	BWR	1000	30	80		Df		2.6	27 [b]	0.063	I/O	M(0)L(2)**E(62)**F(0)C(36)R(0)	
[29]	1975	PWR	1000	30	80		Df		3.0	33 [b]	0.064	I/O	M(0)L(2)**E(64)**F(0)C(33)R(0)	
[4]	2000	PWR	1000	30	75		Df				0.064		M(0)L(6)V(3)**E(71)**F(1)C(8)O(12) T(0)	
[110]	1977	PWR	1000	30	75	1.5	Df	0.3			0.2	I/O		U+Pu recycling
[33]	1976	LWR	1000	40	80	2.34	Df	0.25	2.3	45 [b]	0.171	I/O	ML(1)V(5)**E(72)**F(3)CO(14)D(3)ST(1)	Ore from Ranger
[33]	1976	LWR	1000	40	80	2.34	Ce	0.25	2.3	45 [b]	0.052	I/O	ML(3)V(18)E(6)F(11)**CO(47)**D(12)ST(3)	Ore from Ranger
[33]	1976	LWR	1000	40	80	0.1	Df	0.25	2.3	45 [b]	0.206	I/O	ML(18)V(4)**E(60)**F(3)CO(12)D(3)ST(1)	
[33]	1976	LWR	1000	40	80	0.1	Ce	0.25	2.3	45 [b]	0.087	I/O	ML(42)V(11)E(4)F(7)**CO(28)**D(7)ST(2)	

Notes: [a]=own calculations, AEI=Method of multiplying total cost with the national average energy intensity, [b]=burn-up (GWd tU^{-1}) not conversion rate, [c]=Total cost DM 7.4bn @ 9 MJ/DM, C=Construction, Ce=Centrifuge, [d]=Total cost $17bn @ 22 MJ/$, D=Decommissioning, Df=Gaseous diffusion, E=Enrichment, F=Fuel fabrication, I/O=Input-output-based hybrid analysis, L=Milling, M=Mining, O=Operation, PA=Process analysis, R=Reprocessing, rec.=recycling, S=Waste storage, T=Transport, V=Conversion, W=Waste disposal.

Tab. 3.18a: Results of energy studies of nuclear power systems.

Refe-rence	Year of study	Reactor type	Power rating (MW_{el})	Life time (y)	Load factor (%)	Ore grade (‰)	Enrich-ment tech-nology	% tails	% ^{235}U in fuel	burn-up (GWd / kgU)	GHG intensity $\left(\frac{g\ CO_2 - eq.}{kWh_{el}}\right)$	Ana-lysis type	Stages covered (% of life cycle)	Remarks
[39]	1992	PWR	1000	30			Df				34	I/O	M(4)L(4)V(7)**E(57)**F(4)C(12)O(11)R(0)S(0)T(0)	
[111]	1993	LWR	1300	20	77.6	20	Ce			33	5	I/O		100% nuclear grid "case 1"
[111]	1993	LWR	1300	20	77.6	20	Ce			45	21	I/O		average German grid
[111]	1993	LWR	1300	20	77.6	20	Ce			33	28	I/O		average German grid
[111]	1993	LWR	1300	20	77.6	20	Df			33	84	I/O		average German grid
[113]	1994	LWR	1000				10% Ce			40	6.5	PA	**ML(21)**V(17)E(11)F(0)C(17)O(11)R(17)D(2)SW(1)T(2)	UCPTE grid
[64]	1994	PWR	1100				Ce				7.9	I/O	**MLVEF(66)**C(22)OT(9)DSW(3)	
[118]	1994	LWR	1300	30	68.5						18.63	I/O	ML(35)V(15)E(5)F(1)**C(44)**	
[64]	1994	PWR	1100				Df				25.7	I/O	**MLVEF(90)**C(7)OT(3)DSW(1)	
[119]	1995	LWR	1000	40	70		10% Ce			40	8.88	PA	M(4)L(16)V(16)E(11)F(1)**CO(34)**R(13)S(0)W(3)	Swiss grid
[119]	1995	LWR	1000	40	70		Ce			40	8.92		M(4)L(16)V(16)E(12)F(1)**CO(34)**R(13)S(0)W(3)	Swiss grid
[119]	1995	BWR	1000	30	75		Ce			30	8.93		ML(3)V(12)E(22)F(1)**CO(50)**S(3)W(9)	Japanese grid
[119]	1995	BWR	1000	30	75		Ce			30	10.18		ML(2)V(9)E(15)F(1)**CO(44)**R(16)W(13)	Japanese grid
[119]	1995	BWR	1000	30	75		Df			30	19.41		ML(1)V(5)**E(55)**F(1)CO(23)R(8)W(7)	Japanese grid
[119]	1995	BWR	1000	30	75		Df			30	20.93		ML(1)V(5)**E(67)**F(1)CO(21)S(1)W(4)	Japanese grid
[27]	1996	PWR	600	60	87		Ce	0.28	3.7	40	6.0	PA		AP600 [a]
[27]	1996	BWR	1300	60	87		Ce	0.28	3.7	45	6.0	PA		ABWR [a]
[116]	1996	FBR	1000	30	75	-	Ce				7.8	I/O		
[116]	1996	BWR	1000	30	75		Ce			30	10.4	I/O		Pu recycle
[116]	1996	BWR	1000	30	75		Df			30	21.1	I/O		
[45]	1998	HWR	600/900				-	-	-		3.2	PA	ML(9)V(2)F(0)**C(69)**O(0)D(19)T(0)	CANDU in actual Canadian grid
[45]	1998	HWR	600/900				-	-	-		15.41	PA	ML(3)V(1)F(1)**C(77)**O(15)D(4)T(0)	CANDU in hypothetical fossil grid
[41]	2000	PWR	1000	40	86.8						1.8	PA	COD(100)	Doel 3/4
[41]	2000	PWR	1000	40	86.8						4.0	I/O	COD(100)	Doel 3/4

[120]	2000	BWR	1000	30	70		Ce			30	11	I/O		Pu recycle
[36]	2000	PWR	1000	40	75		Ce		3.0		15	PA	M(3)**LVEF(59)**C(13)O(15)D(0)SW(9)T(1)	
[120]	2000	BWR	1000	30	70		mix			30	21.6	I/O		Pu recycle
[120]	2000	PWR	1000	30	70		mix			30	24.7	I/O		Pu recycle
[120]	2000	BWR	1000	30	70		mix			30	26.4	I/O		no Pu recycle
[120]	2000	PWR	1000	30	70		mix			30	31.4	I/O		no Pu recycle
[120]	2000	BWR	1000	30	70		Df			30	37	I/O		Pu recycle
[24]	2001	PWR	1000	30	80	0.2	Df		3.2		40.3	PA	**MLE(83)**V(7)C(7)S(2)	U from Ranger mine, US grid
[28]	2004	PWR	1000	40	81.4	2.0	Df	0.26	3.8	42.8	5.95	PA	M(9)L(20)V(23)E(9)F(2)**CO(23)**R(5)S(5)W(4)	MOX fuel, French grid
[28]	2004	BWR	1000	40	81.4	2.0	76% Ce	0.26	4.0	48	10.7	PA	M(4)L(9)V(10)**E(60)**F(1)CO(8)R(2)S(3)W(2)	MOX fuel, German grid
[2]	2005	BWR	1030	40	85	0.44	80% Ce	0.28	3.1		3.27	PA	**ML(35)**V(7)E(15)F(5)CD(17)O(6)SW(14)	MLVEF only direct effects
[81]	2005	AGR	625	40	75.8		Ce				5.05	PA	**ML(36)**V(6)E(9)F(5)CD(16)O(12)R(4)SW(13)	Torness
[121, 122]	2005	BWR	1000	30	70		Df		3.4	40	24	I/O	ML(5)V(1)**E(62)**F(3)C(12)O(13)S(3)D(2)T(0)	
[18]	2005	PWR	1000	24	82	1.5	70% Ce	0.2	4.2	46	212 [a]	AEI	ML(3)V(2)E(13)F(1)**C(24)**O(15)**D(24)**S(9)W(11)	
[18]	2005	PWR	1000	24	82	0.1	70% Ce	0.2	4.2	46	527 [a]	AEI	ML(22)V(1)E(5)F(0)C(10)O(6)D(10)S(4)**W(44)**	
[109, 123]	2006	LWR	1000	40	85	127	mix [c]	0.25	3.8	42	17	mix	ML(0)V(0)**E(72)**F(0)CD(6)O(16)S(1)W(5)	Canadian ore
[109, 123]	2006	LWR	1000	40	85	0.5	mix [c]	0.25	3.8	42	54	mix	ML(9)V(2)**E(39)**F(1)CD(21)O(21)S(2)W(5)	CO_2-intensive grid, Australian ore

Notes: [a]=own calculations, AEI=Method of multiplying total cost with the national average energy intensity, [b]=Ore from Australia, Canada and US, [c]=34% Df, 30% Ce, and 36% dilution of high-grade weapon material, C=Construction, Ce=Centrifuge, D=Decommissioning, Df=Gaseous diffusion, E=Enrichment, F=Fuel fabrication, I/O=Input-output-based hybrid analysis, L=Milling, M=Mining, O=Operation, PA=Process analysis, R=Reprocessing, rec.=recycling, S=Waste storage, T=Transport, V=Conversion, W=Waste disposal.

Table 3.18b: Results of greenhouse gas emissions studies of nuclear power systems.

Table 3.18 demonstrates that the energy balance of a nuclear energy system is determined by a number of factors. We identified seven main influences (Table 3.19). We quantified these factors in order to be able to undertake a multiple regression (compare a regression of wind energy studies in [124]). The explained variable is the normalised energy intensity (in GWh_{th} / GWh_{el}; as in Equation 2.3), with explanatory variables as in Table 3.19.

Influence	Variable	Definition	Expected effect on energy ratio
Ore grade	*ore*	‰	negative
Enrichment method	*enrich*	no enrichment=0, centrifuge=1, diffusion=2, mix=1.5	positive
Tails assay	*tails*	%	indeterminate
Conversion rate[16]	*conv*	as in Table 3.18	negative
Vintage year	*year*	as in Table 3.18	negative
Assessment method	*meth*	PA=1, I/O=2, AEI=3	positive
Assessment scope	*scope*	percentage of stages covered; MLVEFCORDSWT=1	positive

Table 3.19: Main factors influencing the energy balance of nuclear power.

The multiple regression of data in Table 3.18 with regard to variables in Table 3.19 ($R^2 = 0.737$) yields some agreement with expected trends (Table 3.20).[17]

	scope	*ore*	*conv*	*tails*	*enrich*	*year*	*meth*
m	0.099	-0.052	-0.132	0.050	0.054	-0.00014	0.216
Δm	0.105	0.017	0.181	0.197	0.035	0.00009	0.044
t	*0.95*	**3.11**	*0.73*	*0.25*	1.55	1.55	**4.89**

Table 3.20: Results from a multiple regression of energy intensities and system parameters.

Excluding Tyner et al's and Storm van Leeuwen and Smith's studies [18, 44] as outliers yields a better regression ($R^2 = 0.912$):

	scope	*ore*	*conv*	*tails*	*enrich*	*year*	*meth*
m	0.099	-0.025	-0.049	0.174	0.079	-0.00009	0.062
Δm	0.038	0.006	0.066	0.072	0.013	0.00003	0.020
t	**2.58**	**3.90**	*0.75*	2.42	**6.19**	**2.66**	**3.15**

Table 3.21: Results from a multiple regression of energy intensities and system parameters, excluding outliers [18, 44].

[16] The conversion rate χ is related to the *burn-up* β through $\chi = \beta \times 24\text{h/d} / (\rho_{iso}\ \eta_{235U}\ f) - 1$, where ρ_{iso} is the energy content of ^{235}U (24,500 $GWh_{th}/t^{235}U$), η_{235U} is the enrichment (%), and f is the fraction of ^{235}U burnt at re-loading (around $^2/_3$).

[17] Note that missing values in Table 3.18 were replaced with averages over all studies.

Based on the adjusted regression, the energy intensity of nuclear power – normalised to a 35-year lifetime at 80% load – can be explained by

$$\eta_{\text{norm}} = -0.025\times ore + 0.079\times enrich + 0.174\times tails - 0.049\times conv$$

$$- 0.00009\times year + 0.062\times meth + 0.099\times scope\ .$$

The m values in Table 3.21 correspond to the coefficients in the regression equations; the Δm values are their standard errors. The t values in Table 3.21 are the results of a t-test (test for significance) for each variable. The most significant variable is the enrichment method, with centrifuges yielding a low energy intensity than diffusion plants. The influence of the ore grade is significantly negative, ie richer ores mean a lower energy intensity. The third significant variable is the method employed: PA yields low, I/O intermediate, and AEI high energy intensities. Increasing the scope naturally always increases the energy intensity, which is reflected in a positive coefficient. Also clearly, recent technologies are slightly more energy efficient than older ones. The choice of enrichment assay also has a strong and significant influence. As explained in Section 3.4, the choice of tails assay represents a compromise between the (monetary and energy) cost of uranium feed and separative work, but in general higher tails assays improve the energy balance. A high conversion rate means that a high percentage of fission products (for example plutonium) are used as reactor fuel, either through higher burn-up or through re-processing, and this appears to improve the energy intensity.

Thus, using the multiple regression formula, an ideal life-cycle assessment (ie full scope, modern reactors, specified ore and enrichment conditions) can be simulated from incomplete and variable literature data. For example, a modern ($year$ = 2006) PWR in once-through mode ($conv$ = 0.55), supplied with uranium from typical Australian ore (ore = 1.5 ‰), enriched using 70% centrifuges ($enrich$ = 1.3) with $tails$ = 0.25% tails assay, assessed using an input-output-based hybrid analysis ($meth$ = 2) covering the full nuclear fuel cycle ($scope$ = 1) results in a regressed energy intensity of η_{norm} = 0.124. However, this regression should be viewed only as a first approximation. In Section 5 of this report we will present a tool that, instead of deducing the overall energy intensity from an empirical relationship, calculates the energy intensity for each fuel cycle stage from technical specifications.

With regard to the greenhouse gas intensity, it is not possible to regress the figures in Table 3.18, because they depend on additional parameters such as the greenhouse gas intensity of the background economy. These parameters were not given in any of the studies. The detailed tool described in Section 5 will calculate greenhouse gas intensities based on specifications on both the nuclear fuel cycle as well as the background economy.

3.14 Main areas of disagreement with Storm van Leeuwen and Smith's study

There are a number of publications by Storm van Leeuwen and Smith (SLS) [18, 46, 125] that have received considerable attention because of these authors' critical attitude regarding nuclear power. In particular, their study has been cited in many submissions to the Prime Minister's Uranium Mining, Processing and Nuclear Energy Review [126-130]. There have also been counter arguments

- by the World Nuclear Association [33], with a rebuttal by SLS [131], and
- by the University of Melbourne [132], with a rebuttal by SL [133], a response by the University of Melbourne [134]; a second rebuttal [135], and a second response [136].

The arguments put forward in the most recent exchanges are not new: The literature documents a similar debate between Mortimer [137, 138] and opponents [139, 140]. Nevertheless, it is of interest to summarise the main points of disagreement between Storm van Leeuwen and Smith, and opposing viewpoints.

The study of Storm van Leeuwen and Smith [18] neither states energy nor greenhouse gas intensities, but instead presents temporal profiles showing break-even points with gas-fired power plants. We have therefore extracted all energy coefficients from the study (Table 3.24) and applied them to a hypothetical nuclear fuel cycle in Australia (see Section 5). For ores of 0.15% grade, we obtain energy and greenhouse gas intensities of 0.66 kWh_{th}/kWh_{el} and 212 g CO_2-e/kWh_{el}, respectively (compare [125] Figure 3). If such rich ores are assumed, the construction and decommissioning of the power plant are the main contributions to energy and greenhouse gas emissions (Table 3.22).

	Electricity (kWh_{el}/kWh_{el})	Thermal (kWh_{th}/kWh_{el})	Total energy (kWh_{th}/kWh_{el})		Total emissions (g CO_2-e/kWh_{el})	
Mining & Milling	0.002	0.012	0.017	2.6%	5.6	2.6%
Clean-up	0.003	0.024	0.033	5.1%	10.7	5.1%
Conversion	0.000	0.012	0.013	2.0%	4.3	2.0%
Enrichment	0.023	0.012	0.083	12.6%	26.7	12.6%
Fuel fabrication	0.001	0.002	0.006	0.8%	1.8	0.8%
Construction	0.020	0.094	0.155	23.6%	50.2	23.6%
Operation	0.007	0.074	0.096	14.7%	31.2	14.7%
Re-processing						
Storage	0.007	0.037	0.059	9.1%	19.3	9.1%
Disposal	0.003	0.029	0.038	5.8%	12.3	5.8%
Decommissioning	0.020	0.094	0.155	23.6%	50.2	23.6%

Table 3.22: Breakdown of the total energy requirement and greenhouse gas emissions for ores of 0.15% grade, using energy intensities from [18], and assuming an average carbon content of 90 g CO_2-e / MJ. Figures were reconstructed from [18] by calculating a) the electrical energy e as $e = S / (1 + x)$, where x is the thermal to electrical energy ratio, and S is the specific energy given in [18], b) the thermal energy as $t = S - e$, and then the total energy requirement as $T = 3e + t$.

If lean ores are assumed (0.01%), the situation changes drastically (Table 3.23): Mining and milling, and the clean-up of the mine site become the main components of the total energy and greenhouse gas requirements. The energy and greenhouse gas intensities are 1.63 kWh_{th}/kWh_{el} and 527 g CO_2-e/kWh_{el}, respectively. Under these conditions – assuming Storm can Leeuwen and Smith's parameters – such a nuclear fuel cycle would indeed not produce net energy, and its greenhouse gas emissions would be comparable to a gas-fired power plant, (compare [18] Figure 10, and [125] Figure 4), and the main reason for this would be the energy required to extract and mill uranium ore, and to dispose of the mine tailings.

	Electricity (kWh_{el}/kWh_{el})	Thermal (kWh_{th}/kWh_{el})	Total energy (kWh_{th}/kWh_{el})		Total emissions (g CO_2-e/kWh_{el})	
Mining & Milling	0.033	0.248	0.351	21.6%	113.6	21.6%
Clean-up	0.060	0.483	0.670	41.2%	217.0	41.2%
Conversion	0.000	0.012	0.013	0.8%	4.3	0.8%
Enrichment	0.023	0.012	0.083	5.1%	26.7	5.1%
Fuel fabrication	0.001	0.002	0.006	0.3%	1.8	0.3%
Construction	0.020	0.094	0.155	9.5%	50.2	9.5%
Operation	0.007	0.074	0.096	5.9%	31.2	5.9%
Re-processing						
Storage	0.007	0.037	0.059	3.7%	19.3	3.7%
Disposal	0.003	0.029	0.038	2.3%	12.3	2.3%
Decommissioning	0.020	0.094	0.155	9.5%	50.2	9.5%

Table 3.23: Breakdown of the total energy requirement and greenhouse gas emissions for ores of 0.01% grade, using energy intensities from [18], and assuming an average carbon content of 90 g CO_2-e / MJ. Figures were reconstructed from [18] by calculating a) the electrical energy e as $e = S / (1 + x)$, where x is the thermal to electrical energy ratio, and S is the specific energy given in [18], b) the thermal energy as $t = S - e$, and then the total energy requirement as $T = 3e + t$.

It is therefore an important question to ask whether Storm van Leeuwen and Smith's assumptions are realistic or not. Table 3.24 provides a comparison of energy intensities from the literature and Storm van Leeuwen and Smith's figures. This table demonstrates very clearly that the main differences arise for the following fuel cycle stages: mine clean-up construction, operation, decommissioning, spent fuel storage, ILW/LLW disposal, and HLW disposal.

The commentary in Table 3.25 attempts to explain some of the main discrepancies, supported by more detailed explanations previously in this Section. However, some of the assumption made by Storm van Leeuwen and Smith relate to waste disposal practices in the nuclear energy industry. To critique these practices is outside the scope of this study, which is indicated in the corresponding rows of Table 3.25.

For our own life-cycle assessment of nuclear energy in Australia (Section 5), we have followed the argumentation in Table 3.25.

Stage	Unit	This review			Strom van Leeuwen and Smith [18] [a]			Difference		
		Electricity	Thermal energy	Total energy	Electricity	Thermal energy	Total energy	Electricity	Thermal energy	Total energy
Mining	$GWh_{el/th}$/t ore	5.43E-5	1.26E-4	2.95E-4	7.61E-5 [b]	5.71E-4 [b]	8.07E-4	-5%	68%	37%
Milling	$GWh_{el/th}$/t ore	2.58E-5	2.15E-4	2.95E-4						
Conversion	$GWh_{el/th}$/t U_3O_8	1.47E-2	3.96E-1	4.41E-1	1.47E-2	3.96E-1	4.41E-1	0%	0%	0%
Enrichment (70%centrifuge)	$GWh_{el/th}$/tSWU	9.29E-1	2.53E-1	3.13E+0	1.01E+0	5.11E-1	3.64E+0	9%	102%	16%
Fuel fabrication	$GWh_{el/th}$/t ^{235}U	3.01E-1	7.52E-1	1.69E+0	3.00E-1	7.50E-1	1.68E+0	0%	0%	0%
Construction	$GWh_{el/th}/GW_{el}$	1.37E+2	3.69E+3	4.11E+3	3.88E+3	1.86E+4	3.06E+4	2739%	405%	645%
Operation	$GWh_{el/th}/GWy_{el}$	1.00E+1	2.70E+2	3.01E+2	4.79E+1	5.08E+2	6.56E+2	379%	88%	118%
Decommissioning	$GWh_{el/th}/GW_{el}$	1.37E+1	3.69E+2	4.11E+2	3.88E+2	1.86E+3	3.06E+3	2739%	405%	645%
Storage	$GWh_{el/th}$/t waste	8.00E-2	6.00E-1	8.48E-1	4.40E-1	2.20E+0	3.56E+0	450%	267%	320%
ILW/LLW disposal	$GWh_{el/th}$/t waste	2.44E-2	1.09E-3	7.68E-2	2.49E-2	4.47E-1	5.24E-1	2%	40764%	583%
HLW disposal	$GWh_{el/th}$/t waste	3.29E-1	1.19E-1	1.14E+0	3.09E-1	2.47E+0	3.43E+0	-6%	1975%	201%
Depleted uranium	$GWh_{el/th}$/t U	2.49E-2	4.47E-1	5.24E-1	2.49E-2	4.47E-1	5.24E-1	0%	0%	0%
Mine clean-up	$GWh_{el/th}$/t tailings	-	-	-	1.39E-4	1.11E-3	1.54E-3			

Table 3.24: Comparison of energy intensities – typical values from the literature, and Storm van Leeuwen and Smith [18] ([a]= Figures were reconstructed from [18] by calculating a) the electrical energy e as $e = S / (1 + x)$, where x is the thermal to electrical energy ratio, and S is the specific energy given in [18], b) the thermal energy as $t = S – e$, and then the total energy requirement as $T = 3e + t$; [b]= mining and milling).

Storm van Leeuwen and Smith	World Nuclear Association, University of Melbourne, and this study
Energy intensities of uranium **mining and milling** vary by an order of magnitude, and that therefore the energy intensity for a particular situation may be grossly underestimated.	Using a linear relationship between energy requirements and ore grade, the energy intensity may also be grossly overestimated if uranium is mined together with other products [132, 134, 141, 142].
In-situ leaching (ISL) contaminates aquifers and is hence too harmful for the environment.	Outside the scope of this report.
The energy required for the **construction** of a 1000 MW reactor is in the order of 25,000 GWh_{th}.	SLS's energy assessment method is flawed for reasons given in Section 3.6. More realistic values are 4,100 GWh_{th} (LWR) to 9,800 GWh_{th} (HWR).
The energy required for the **operation** of a 1000 MW reactor is in the order of 889 GWh_{th} per year.	SLS's energy assessment method is flawed for reasons given in Section 3.6. A more realistic value is 300 GWh_{th} per year.
The energy required for the **storage and disposal** of high-level radioactive waste is in the order of 3,500 GWh_{th} per tonne HLW.	SLS's cost figures could not be queried, however their energy assessment method is flawed for reasons given in Section 3.6. Figures reported in the literature are around 1,000 GWh_{th} per tonne.
Plant decommissioning – if properly done – will incur costs in the order of 200% of a power plant's construction costs. Tritium and ^{14}C in cooling water discharged into rivers needs to be dealt with.	Determining whether current plant decommissioning practices are adequate from a radiation protection perspective is outside the scope of this report.
Mine restoration to "green fields" conditions requires isolating tailings between layers of bentonite, ultimately requiring four times the energy of mining.	Determining whether current tailings treatment practices are adequate from a radiation protection perspective is outside the scope of this report. Notwithstanding this, the energy intensity may also be overestimated if uranium is mined together with other products [132, 134, 141].

Table 3.25: Main areas of disagreement between Storm van Leeuwen and Smith (SLS) [18, 46, 125], this study, and other studies.

Finally, an apparent discrepancy between Storm van Leeuwen and Smith's regression and the University of Melbourne's calculation of energy requirements for mining and milling at the Olympic Dam mine in South Australia [132, 143] disappears once the full range of products at Olympic Dam is taken into account. Including the copper into the ore grade yields the following results (Table 3.26):

	SLS	Including copper		Calculation via
A	5.55	5.55	GJ / t ore for mining and milling	
B	0.05%	2.53%	grade	
C	85.8%	96.8%	recovery rate (yield)	regression formula
D	12,943	227	GJ / t U_3O_8	D=A /B /C
E	15.26	0.27	GJ / kgU	E=D / 848kgU/tU_3O_8
F	4,600	4,600	tU / y at Olympic Dam	
G	70,209	1,230	TJ / y predicted at Olympic Dam	G = E x F
H	5,477	5,477	TJ / y measured at Olympic Dam	

Table 3.26: Solution to the discrepancy between Storm van Leeuwen and Smith [18], and the University of Melbourne [132, 143].

A slight difference exists between the calculation in Table 3.26 and the results obtained by University of Melbourne [132, 143], since we calculated the recovery rate (yield) of Olympic Dam according to Storm van Leeuwen and Smith's regression formula (85.8%), while the researchers at the University of Melbourne set this rate to 100%. The actual recovery rate of 97% [143] is well reproduced if the ore grade is raised from 0.05% (only uranium) to 2.53% (including copper). The regressed energy requirement does not agree with the measured energy use, however it is now in the right order of magnitude.

The discrepancy between Storm van Leeuwen and Smith's regression formula and the data for the Rössing mine in Namibia [144] and the Ranger mine in Australia [145] could not be resolved. BHP Billiton [142] states that "*there are some operations in South Africa (Palabora, Rossing) that, like Olympic Dam, make a copper concentrate (but not necessarily refined copper) and uranium oxide.*" In our calculations we exclude these mines as outliers (see Figure 5.1).

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4 Nuclear power in Australia: Two scenarios

The two scenarios chosen for study are:

4.1	Short to Mid-term Scenario	15 years from 2006-2020
4.2	Mid- to Long-term Scenario	30 years from 2020-2050.

The estimated electricity demand and the types of nuclear reactors are presented for each scenario and the technical data for each stage of the nuclear fuel cycle are summarised.

4.1 Short- to mid-term scenario

4.1.1 Estimation of electricity demand

The basic input data on the Australian electricity demand has been taken from a recent ABARE study. We assume a demand of about 276,000 GWh_{el} in 2020. A distribution loss of 5% is assumed. The capacity required at the power station fences is therefore 33 GW_{el}. It is further assumed that the nuclear power component of this expected demand is 10%. This results in an expected demand of 27,600 GWh_{el} from nuclear power plants in 2020. The capacity factor of the nuclear plants is assumed to be 85% and the justification of this factor is discussed in Section 4.1.3 (g). The nominal total capacity of the plants is therefore required to be 3.9 GW_{el} in 2020 and equivalent to 3 x 1,300 MW_{el} plants.

4.1.2 Nuclear reactors types

The types of nuclear power plants considered in the short to medium term are

* APR 1000 (Westinghouse): It is nominally a 1000 MWe PWR. It is expected that a First of a Kind Engineering (FOAKE) plant will be constructed in the USA starting in 2009 with completion by about 2014. A similar plant could be constructed in Australia. This type was selected as a reference in the Consulting Report commissioned by ANSTO earlier this year from Professor Gittus of the UK.
* APR 1400 (Westinghouse/Korea): This type is currently under construction in Korea at a nominal capacity of 1,350 MWe and is larger than the APR1000. Selection of this type could be more appropriate for Australia in the short term since only three would be required to achieve the 3,900 MWe required instead of four APR 1000 reactors and there is experience at building these in Korea.
* ABWR (GE, Hitachi, Toshiba): This basic design is a 1300 MWe BWR operating in Japan.
* EPR (Areva, France): The first two of this type of PWR with 1,550+ MWe capacity are under construction in Finland and France.

* CANDU-9 and ACR1000: CANDU-9 can be 925-1,300 MWe and ACR 1000 is 1,000 MWe and both would be FOAKE if build in Canada and then in Australia. They are heavy water reactors.
* PBMR Eskom, South Africa: This is currently designed as a 160MWe modular high temperature reactor to be constructed as 4 x 160 modules = 640 MWe and would be FOAKE when built in South Africa as a demonstration module starting construction in 2007. This is a pebble bed reactor with the fuel contained in ceramic/graphite spheres each about the size of a tennis ball and the circulating gas is helium which drives a gas turbine.

Reference type - The APR 1400 (Westinghouse/Korea) is chosen as a reference type because its output would be suitable for three stations of 1,300MWe totalling 3,900MWe to give a capacity approximately matching demand by 2020. This assumes for this theoretical study that three plants could be built by 2020. The scenario requires three plants to be brought on line as follows: Plant 1 - 2016, Plant 2 - 2018 and Plant 3 - 2020.

4.1.3 Description of stages

The basic nuclear power construction program in this period could be achieved by only mining and milling uranium in Australia, and using overseas services for conversion, enrichment and fuel fabrication. However it is assumed for this study that all key fuel cycle stages are not set up before 2020

(a) Uranium mining

In 2006 there are three uranium mines in operation in Australia. The size of the deposits supporting these mines, their grades, their output in 2005 and their likely lifetime based on proven deposits are (information from UIC Briefing Papers 1 and 2):

(i) Ranger, NT, owned by ERA/Rio Tinto; open pit mining
Remaining deposit: 14,700 te U at 0.15% grade + 29,700 te U at 0.23%
Production in 2005: 5006 te U
Likely lifetime: 9-10 years

Note – Nearby Jabiluka deposit is very large but cannot be mined unless the traditional owners grant approval.

(ii) Olympic Dam, SA, owned by BHP-Billiton; u/ground mining with copper/gold
Remaining deposit: 319,000 te U proven (over 1M te probable) – low grade ore but the uranium is a by-product of the principal copper ore with gold as an additional by-product.
Production in 2005: 3,688 te U (plans for expansion to 9,000 te U)
Likely lifetime: >20 years at 3x expansion on proven reserves

(iii) Beverley, SA, owned by Heathgate Resources; in-situ leach mining
Remaining deposit: 21,000 te U at 0.18%
Production in 2005: 825 te U
Likely lifetime: 10-20 years at present rate

Note - Nearby Honeymoon deposit of 2,900 te U at 0.24% may be mined in-situ in the next 3 years, but will only have a short lifetime.

(b) Uranium milling

(i) Ranger milling plant – located at Ranger minesite (see above for production)
(ii) Olympic Dam milling plant – located at minesite (see above for production)
(iii) Beverley milling plant – located at in-situ site (see above for production).

The total uranium production to support the initial fuel loadings for the proposed three 1,300MWe reactors is estimated to be 100 teU per reactor plus the replacement fuel at one-third (34 teU) of the core every year after the first three years. It is assumed that conversion operates at 99.5% efficiency and enrichment assays are 3.5% U-235 product with 0.25% tails with a 6:1 ratio of feed to product. The reactor capacity factor is assumed to be 85%. A choice of other product and tails assays or other reactor capacity will change the feed uranium and separative work requirements. For a discussion of the reactor capacity factor see later under section (g). The annual and cumulative requirements of uranium feed are:

Year	2015	2016	2017	2018	2019	2020
U_3O_8, te U (Initial cores)	600		600		600	
Replacement cores, te U			204	408	408	408
Cumulative, te U	600	600	1404	1812	2820	3432

(c) Conversion to Uranium Hexafluoride (UF_6)

In order to supply the enrichment plant the uranium product from the uranium milling plants must be converted into UF6 in a conversion plant. The total UF_6 requirements for these three reactors in this scenario are 600 te U in year 2015 (one year before Reactor 1 start-up), 600 te U in 2017 (one year before Reactor 2 start up), 800 te U in 2019 (one year before Reactor 3 start up plus first replacement fuel for Reactor 1) and 200 te U in 2020. The annual and cumulative totals are therefore:

Year	2015	2016	2017	2018	2019	2020
UF_6, te U (Initial cores)	600		600		600	
Replacement cores, te U			204	408	408	408
Cumulative, te U	600	600	1404	1812	2820	3432

The generally accepted size of a conversion plant is 1,000 – 3,000 te U/a. This study assumes that a plant would not start up in Australia until after 2020, and that the conversion services are purchased from overseas conversion plants until then. An Australian conversion plant could be sited close to an enrichment plant to minimise the transport distance of the product.

(d) Enrichment

The enrichment services to supply the fuel fabrication plant for the 3900 MWe of reactors to operate by 2020 are estimated assuming 3.5% U-235 product and 0.25% tails assays with a 6:1 feed to product ratio; this also assumes a 100 te U fuel loading and one-third core replacement every three years to produce 9300 M KWh electricity/year at 85% capacity factor. The separative work required is estimated to be 4.8 SWU (Separative Work Units) per kg U product or 160,000 SWU for 100 te U product in an initial core and 53,000 SWU per 34 teU replacement core. The annual and cumulative separative work requirements are estimated as follows:

Year	2015	2016	2017	2018	2019	2020
Initial cores, 1000 SWU	160	-	160	-	160	-
Replacement cores, 1000 SWU	-	-	53	53	106	159
Cumulative, 1000 SWU	160	160	373	426	692	851

The generally accepted size of a commercial centrifuge enrichment plant is considered to be about 1,000,000 SWU per year. This study assumes enrichment services are purchased from an overseas enrichment plant until after 2020.

(e) Fuel fabrication

The enriched UF_6 is supplied to the fuel fabrication plant which converts it to UO_2, encapsulates in the metal cladding and assembles the fuel rods into fuel element assemblies. The amount of uranium required for fuel fabrication for the 3,900 MWe of reactors is estimated to be 100 te for each initial core of the three reactors and 34 teU for each replacement core (one-third of each core per year after the first three years). Annual and cumulative requirements are estimated to be:

Year	2015	2016	2017	2018	2019	2020
Fuel, te U (Initial cores)	100	-	100	-	100	-
Replacement cores, te U	-	-	34	68	68	102
Cumulative, te U	100	100	234	302	470	572

The generally accepted minimum size of a fuel fabrication plant is 100-200 teU per year hence it is assumed services are purchased from overseas until after 2020. The initial cores and at least the first replacement cores are usually provided by the reactor vendor.

(f) Construction of the nuclear reactors

For the first of the three reactors to come on line by 2016, construction would have to start by site preparation in about 2010 with first pour of concrete for Reactor 1 in 2012, followed by Reactor 2 in 2014 and Reactor 3 in 2016.

The current cost for the reactor recommended is about US$1400 /KWe installed but this is dependent on the site location and does not include interest during construction.

Sites in three different locations are assumed to enable the 1,300 MWe capacities to be integrated into the state grids. Coastal sites would provide easy access to seawater cooling.

(g) Operation of the reactors

The reactors are assumed to commence operation in 2016, 2018 and 2020. A capacity factor of 85% is assumed for these reactors after the first year of operation of each reactor. Evidence to support this capacity factor is provided by the World Nuclear Association review of world reactors (2006) and the review of data for the USA in Nuclear News, September 2006.

(h) Decommissioning of the reactors

The initial design lifetime of this type of reactor (PWR) has been 30 years historically, but many have been given extended lifetimes to 60 years and sometimes also upgrades in capacity. The APR1400 has been designed to have a lifetime of 60 years. It is therefore unlikely that reactors constructed in the 2016 to 2020 timescale would require decommissioning until at least 2076-2080.

(i) Storage of the nuclear waste

The spent fuel would be stored in storage pools at the reactors for a minimum of 5 years to reduce the level of radiation. If the spent fuel is defined as waste and not reprocessed and recycled it would be stored at a central away-from-reactor site which could package it for final disposal. If the spent fuel is to be reprocessed it would be transferred to a storage facility at a central reprocessing plant to await reprocessing.

(j) Reprocessing

If the spent fuel is to be reprocessed, the fuel would be stored for a period of time to reduce its radioactivity and to build up sufficient fuel to feed into the plant continuously or in campaigns depending on the size of the plant. The amount of spent fuel from the initial three reactors in this short to mid-term scenario is estimated to be 34 te Heavy Metal (HM) from reactor 1 discharged in 2019, 68 te from reactors 1 & 2 in 2020, followed by 103 te per year from the three reactors each year thereafter. The storage capacity at the reactors would accommodate this spent fuel for at least five years. The total accumulated by 2020 would be 103 te HM. Since the minimum sizes of reprocessing plants are generally considered to be 300 te HM/a (small) to 1,500 teHM/a (large), it is assumed a reprocessing plant would not be established in Australia until at least 2030. In this case spent fuel storage would be needed for at least 10 years at each reactor.

(k) Final disposal of the nuclear waste

The generally accepted concept in many countries using nuclear power is that spent fuel or reprocessed vitrified waste should be stored or disposed of in deep repositories in stable geological strata, at least 500 - 1000 m deep. It would take several years to identify and choose a site in Australia and complete construction, so this is considered under the mid-long term scenario.

(l) All transport associated with (a) to (k)

The typical transport distances estimated for the above stages will depend on the assumptions made as to the location of the mines, the conversion and enrichment plants and the reactors. To allow access to sea water for cooling and integration into the electricity grid, the nuclear reactors are assumed to be on the coast in Queensland, NSW, Victoria, South Australia or Western Australia. The uranium mine sites are already fixed for the short-mid term scenario in the NT and South Australia.

The transport distances for the stages in the nuclear fuel cycle are summarised in the following Table.

Stage	Location	Distance to next stage km	Form of transport
Mining	NT, SA		Local road
Milling	NT, SA	On mine site	Road
Conversion, Australia	SA, Qld	1,000	Road
if overseas	USA, Canada, France, Russia	20,000	Sea & road from ports
Enrichment, Australia	SA, Qld	20,000	Sea & road from ports
if overseas	UK, France, USA	20,000	Sea & road from ports
Fuel Fabrication	France, USA	less than 500	Road
Reactor	NSW, SA, WA	1,000	Sea & road from ports
Reprocessing Plant	SA, Qld, NT	1,000	Road
Waste disposal site	SA, NT	500-1,000	Road

4.2 Mid- to long-term scenario

4.2.1 Estimation of electricity demand

The estimation of the likely electricity demand to 2050 is very difficult and therefore the only basic assumption made is that it will increase at 3% per year with the use of fossil fuels being slowly replaced by nuclear power and renewables. The proportion of nuclear power is assumed to increase from about 10% in 2020 to 15% in 2030, 20% in 2040 and 25% in 2050.

The estimated demand, nuclear power components from 2020 to 2050 and numbers and capacities of reactors are given in Table 4.1.

Year	2020	2025	2030	2040	2050
Total capacity, MWe	33,705	39,073	45,296	60,872	77,110
Nuclear supplied, MWe	3,370	3,907	6,794	12,174	19,277
Nuclear capacity, MWe (assuming 85% CF; rounded)	4,000	4,600	8,000	14,300	22,700
Increment added, MWe		600	3,400	6,300	8,400
No. of reactors added		1x600	2x1,300 + 1x600	3x1,500 + 3x 600	4x1,500 + 4x600
Total No of reactors (see Section 3.2)	3x1,300	3x1,300 + 1x600	5x1,300 + 2x600	3x1,500 + 5x1,300 + 5x600	7x1,500 + 5x1,300 + 9x600

Table 4.1: Estimated demand, nuclear power components from 2020 to 2050 and numbers and capacities of reactors.

4.2.2 Reactor types

There is considerable development work underway in several countries in international groups to provide improved advanced nuclear reactors for this time period. The objectives are to simplify the current designs to reduce costs, improve safety and improve proliferation resistance of the associated fuel cycles. Advanced concepts being studied include passive safety, longer times between refuelling and reduced amounts of radioactive waste.

It is very difficult at the present early stage of development to select which should be chosen as a reference concept for the Australian scenario for 2020-2050. However, the following systems are the two most promising designs and for which technical data are available for analysis:

* Supercritical-water-cooled Reactor (SCWR) because this is an evolutionary design based on current advanced pressurised water reactors (PWRs) but with a higher operating temperature in the supercritical water region. Information on materials used and energy required to produce the reactor are therefore available from the existing PWRs.
* The Very High Temperature Reactor for which there has been operating experience with old designs in the 1970s and 1980s and which is being developed in the next few years in a small modular version in South Africa as the Pebble Bed Modular Reactor. For the purpose of this period, the basic unit will be assumed to be the Pebble Bed Modular Reactor with 4 x 160 MWe rounded to 600 MWe.

4.2.3 Description of stages

(a) Uranium mining

The uranium mines operating in Australia from 2020 may be different to those assumed to operate to 2020. Of the three mines in the short term (Ranger, Olympic Dam and Beverley), only Olympic Dam has a large enough resources base to operate after 2020. Likely production will be 10,000 te U per year from 2020 for at least 10 years. This will still be a low grade underground deposit, but the low grade is compensated for by the mine being operated as a copper and gold deposit with uranium as a by-product, hence the bulk of the mining costs and energy used are costed against copper and gold recovery. The continuing operation of the Ranger mine and mill will depend largely upon whether additional uranium resources are discovered near Ranger. Continued operation of the mill will also depend on whether the traditional owners grant approval to mine the large Jabiluka deposit. The Beverley deposit only has a likely lifetime of about 10-20 years from 2006 at its current production rate, and the nearby Honeymoon deposit may only be mined by the in-situ method from 2008 for about 5 years as it is a small deposit.

Other potential deposits for mining in the 2020-2050 period are in SA, WA, Qld and the NT, and it is expected that exploration programs will discover substantial new resources. Therefore it is likely that the amount of uranium required to support a nuclear power program in Australia will be available from Australian resources. These are assumed to be a combination of deposits mined by underground or open-cut methods with an estimated average grade of 0.15% U_3O_8, except for Olympic Dam.

(b) Uranium milling

It is assumed that milling will continue to be carried out at mills alongside uranium deposits, except at Jabiluka, which if mined after 2020, would almost certainly be milled at the Ranger plant nearby.

The total uranium production to support the initial fuel loadings for the proposed future 1,300 MWe reactors is estimated to be 100 teU per reactor plus the replacement fuel at one-third (34 teU) of the core every year after the first three years. The initial fuel loading for 1,500 MWe reactors is estimated to be 112 teU and replacement fuel 37 teU per year while the initial fuel loading for the 600 MWe PBMRs is 40 teU and replacement fuel 13 teU/year. It is assumed that conversion operates at 99.5 % efficiency and enrichment assays are 3.5% U-235 product with 0.25% tails. The reactor capacity factor is assumed to be 85%. A choice of other product and tails assays or other reactor capacity will change the feed uranium and separative work requirements. For a discussion of the reactor capacity factor see later under section (g). The cumulative requirements for uranium from 2015 are:

Year	2020	2025	2030	2035	2040	2050
U_3O_8, te U (Initial cores)	1800	2040	3480	5064	6216	9864
Replacement cores, te U	1632	4692	7110	9570	15510	32382
Cumulative, te U (from 2015)	3432	6732	10590	14634	21726	42246

(c) Conversion to Uranium Hexafluoride (UF_6)

It is assumed a conversion plant is constructed in Australia after 2020. The estimated cumulative totals on the same assumptions for uranium above are:

Year	2020	2025	2030	2035	2040	2050
UF6, te U (Initial core)	1800	2040	3480	5064	6216	9864
Replacement cores, te U	1632	4692	7110	9570	15510	32382
Cumulative, te U (from 2015)	3432	6732	10590	14634	21726	42246

(d) Enrichment

Similarly to conversion, it is assumed an enrichment plant is established in Australia after 2020. It is assumed that a centrifuge enrichment plant based on technology licensed from Urenco is constructed starting in 2015 so that it can provide the enrichment services needed by 2020 with any surplus production being exported. The cumulative separative work requirements from 2015 are estimated as follows:

Year	2020	2025	2030	2035	2040	2050
Initial cores, 1000 SW	480	645	965	1490	2000	3380
Replacement cores, 1000 SWU	371	1166	2342	3912	6227	12987
(Total from 2015)	851	1811	3307	5402	8227	16367

The generally accepted size of a commercial centrifuge enrichment plant is considered to be about 1,000,000 SWU per year.

(e) Fuel fabrication

Similarly to conversion and enrichment, it is assumed a fuel fabrication plant is constructed in Australia for fuel for the advanced PWRs proposed or the advanced gas-cooled fixed or pebble bed high temperature reactors proposed. The construction is assumed to start by 2020 so that all nuclear fuel required for Australian reactors after 2025 would be supplied from the Australian plant under license from overseas nuclear fuel manufacturers. The cumulative requirements for enriched UF6 feed are:

Year	2020	2025	2030	2035	2040	2050
UF_6, te U (Initial cores)	480	645	965	1490	2000	3380
Replacement cores, te U	371	1166	2342	3912	6227	12987
Total , te U	851	1811	3307	5402	8227	16367

(f) Construction of the nuclear reactors

For this scenario it is assumed that the new reactors are brought on line from 2020-2050 according to the schedule in Table 4.1. This involves construction of standardised advanced PWRs of 1,300 MWe capacity in multiple units on the same sites as the first three reactors (in NSW, Qld and WA), with additional units being constructed at new sites in SA and the NT. The first of the advanced Pebble Bed Modular Reactors (PBMRs) of nominally 4 units totalling 600 MWe capacity is constructed in 2025, followed by 2 x 600MWe by 2030, 3 by 2040 and 4 by 2050. The first three of the larger supercritical water reactors of nominally 1,500 MWe capacity is constructed by 2040 with an additional 4 by 2050. The total number of nuclear power stations in Australia by 2050 would be 21, equivalent to about 25% of total electricity demand.

The estimated cost for these reactors is about US$1,200/KWe installed but this is dependent on the site location and does not include interest during construction (see information in Briefing Papers on Advanced Reactors from the UIC, 2006). The reactors would be designed to have a 60 year lifetime

(g) Operation of the reactors

The reactors would commence operation progressively from 2020. A capacity factor of 85% is assumed for these reactors and that this is achieved after the first year of operation of each reactor. Evidence to support this capacity factor is provided by the World Nuclear Association review of world reactors (2006) and the review of data for the USA in Nuclear News, September 2006.

(h) Decommissioning of the reactors

The initial design lifetime of these types of advanced reactors would be 60 years. It is therefore unlikely that reactors constructed in the 2020 to 2050 timescale would require decommissioning until at least 2080-2110. For the sake of completeness in the life-cycle analysis, decommissioning has been included.

(i) Storage of the nuclear waste

The spent fuel would be stored in storage pools at the reactors for a minimum of 5 years to reduce the level of radiation. If the spent fuel is defined as waste and not reprocessed and recycled it can be stored at a central facility away-from-reactor site where it could be packaged for final disposal. If the spent fuel is to be reprocessed it can be transferred to a storage facility at a central reprocessing plant to await reprocessing.

(j) Reprocessing

If the spent fuel is reprocessed, the fuel would be stored for a period of time to reduce its radioactivity and to build up sufficient fuel to feed into the plant continuously or in campaigns depending on the size of the plant.

The storage capacity at each of the reactors would accommodate spent fuel for at least five years. The total accumulated by 2020 is only 50 teHM. The totals accumulated by 2030, 2040 and 2050 if not reprocessed are given below, based on the electricity supplied at the assumed 85% capacity factor. The minimum sizes of commercial reprocessing plants are generally considered to be 300 te HM/a (small) to 1,500 teHM/a (large), and the 300 te/a capacity would not be exceeded in Australia until after 2030. The spent fuel is therefore assumed to be stored at enlarged storage pools at the reactors or at a centralised away-from-reactor storage facility.

Year	2020	2025	2030	2040	2050
Electricity supplied, MWe	3900	4500	7700	14000	22400
Spent fuel arising, te HM/a	102	102	149	249	412
Cumulative spent fuel, te HM	238	748	1391	3405	6825

(k) Final disposal of the nuclear waste

The generally accepted concept in many countries using nuclear power is that spent fuel or reprocessed vitrified waste should be stored or disposed of in deep repositories in stable geological strata, at least 500 - 1000 m deep. Estimates of the cumulative amounts of high level waste to be disposed of in an underground repository assuming 0.2 te waste per te spent fuel are:

Year	2020	2025	2030	2040	2050
Spent fuel, te HM	238	748	1391	3405	6825
Vitrified waste ,te	48	150	278	681	1365

(l) All transport associated with (a) to (k)

The typical transport distances estimated for the above stages depend on the assumptions made as to the location of the mines, the conversion and enrichment plants and the reactors. The assumed sites for the nuclear reactors are on the coast in Queensland, NSW, Victoria, South Australia and Western Australia. The uranium mine sites are already fixed for the short-mid term scenario in the NT and South Australia. There would be advantages in locating a conversion plant close to the enrichment plant. Transport distances by road from the NT mine to South Australia or Queensland are assumed to be 1,000 km. Transport distances for fuel to the reactors from the enrichment plant are assumed to be less than 1000 km.

Stage	Possible Location	Distance to next stage, km	Form of transport
Mining	NT, SA, WA	on mine site	Local road
Milling	NT, SA, WA	1,000	Road
Conversion, Australia	SA, Qld	less than 100	Road
Enrichment, Australia	SA, Qld	less than 100	Road
Fuel Fabrication	SA, Qld	less than 1,000	Road
Reactor	NSW, SA, WA, NT	less than 1,000	Road
Reprocessing Plant	SA, Qld, or NT	1,000	Road
Waste disposal site	SA, NT	-	Road

5 Life-cycle energy and greenhouse gas emissions of nuclear power in Australia

5.1 Assumptions

Today, about 15% of electricity consumed world-wide is generated from nuclear power [1]. Most of the installation of capacity happened in the 1970s and 1980s, while after 1990 the percentage of nuclear power in the overall mix stayed constant. Regional contributions vary between 30% (Europe), 20% (Eurasia including Russia, and USA), 10% (Asia), and less than 5% for South America, Middle East and Africa. Electricity consumption is projected to increase to 30,000 billion kWh in 2030 [2].

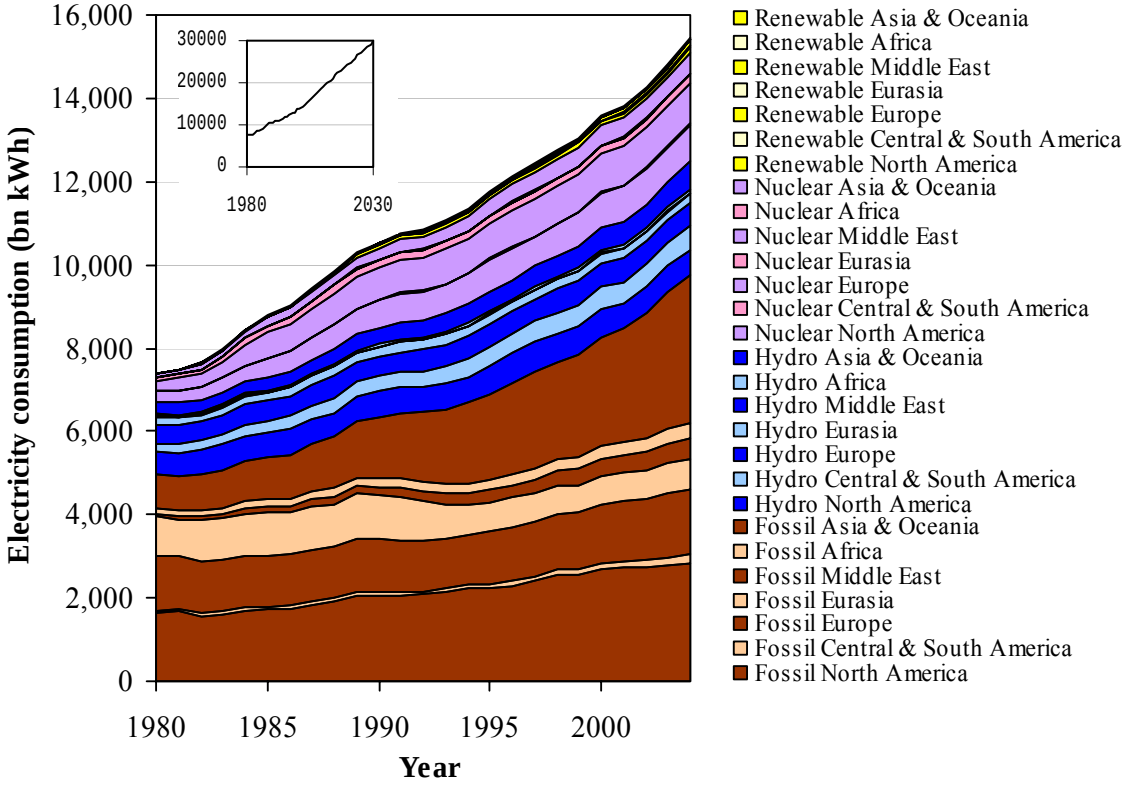


Figure 5.1: World electricity consumption by energy source and region, and forecast to 2030 (compiled from data in [1, 2]).

In Australia, electricity consumption has been growing steadily (Figure 5.2). Most of electricity is generated using black coal (New South Wales, Queensland), brown coal (Victoria), natural gas (Northern Territory), black coal and natural gas (Western Australia, South Australia), and hydro-potential (Tasmania).

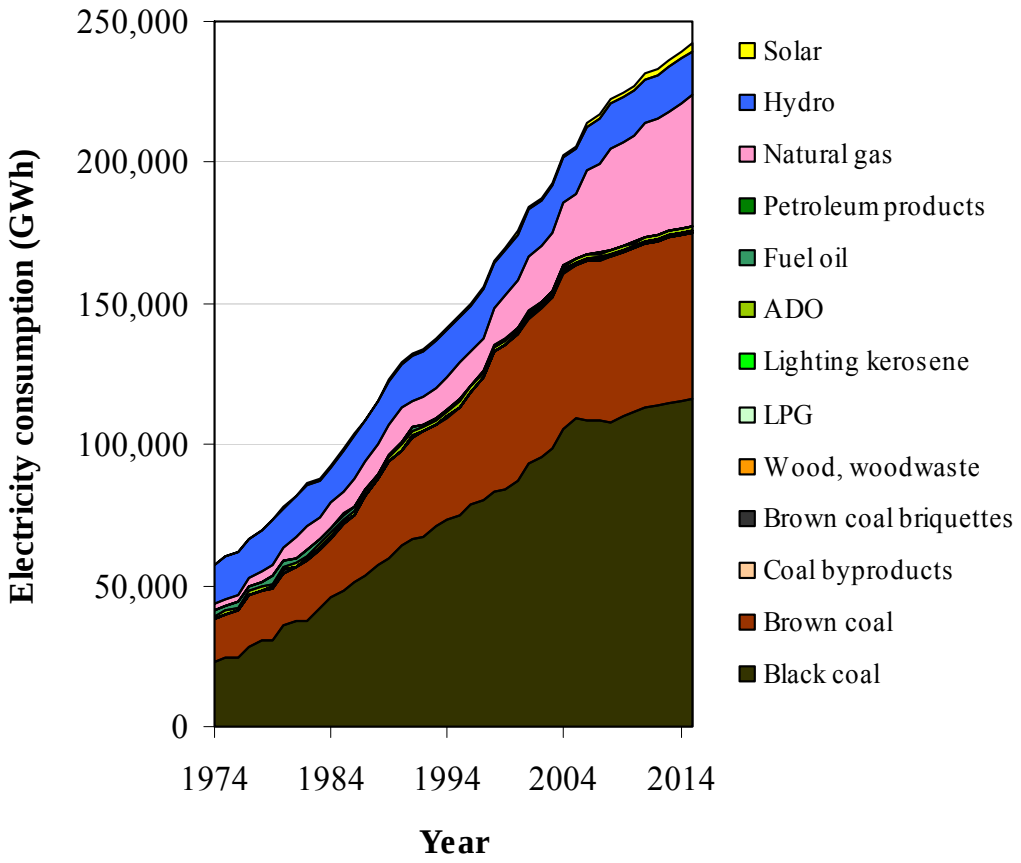


Figure 5.2: Australian electricity consumption by energy source, historical data and forecast to 2015 (compiled from data in [3, 4]).

The life-cycle assessment carried out here is for a hypothetical nuclear industry in Australia providing around 10% of the electrical energy projected in 2020, which is around 27,000 GWh_{el}/y. The authors felt that this percentage is at the limit of what complies with the methodological requirement that "*none of the supply systems or supporting industries under study is large enough to perturb the existing data*", i.e. the data on the background economy [5].

The lifetime of uranium resources for supplying Australia's or the world's nuclear power plants under certain demand scenarios depends critically on assumptions about recoverable resources, ore grade distributions, by-products of uranium in mines, future exploration success, the exploitation of breeder reactors and plutonium in MOX fuels, and market conditions [6-11]. These aspects are however outside the scope of this study.

In the following, in order to be able to calculate both energy and greenhouse gas intensities, we keep requirements of electrical and thermal energy separate. Ideally the analysis should also separate the various fuels, however most studies do not reveal this level of detail. In this work, we multiply electricity and fuel requirements with a greenhouse gas coefficients that represent the energy mix of the Australian economy.

5.1.1 Uranium mining and milling

Published statistics on energy consumption in Australia do not explicitly distinguish the uranium mining sector; uranium is lumped together with other metals in the 'Non-ferrous metal ore mining' sector [12].

The Australian input-output database does distinguish the sector '13190020 Uranium concentrates', however data on this commodity only exists in form of "commodity cards" detailing the destinations of the monetary output of this sector (i.e. export), rather than a list of inputs, i.e. a "production recipe" [13].

The strategy for determining energy and greenhouse gas embodiments for Australian uranium mining and milling therefore has to start with a detailed process analysis, assisted by mining and milling data for other metals mined in Australia. This process analysis then has to be complemented with an input-output-based "overhead" calculated from the non-ferrous metal mining sector.

Material	Year	Energy use (PJ, [12, 14])	Ore extracted (Mt, [14, 15])	Energy intensity (GJ/t ore)	Concen-tration of product	Energy intensity (GJ/t product)
Iron ore	1997-98	11.5	169.6	0.068	≈ 18%[1]	0.38
Uranium, Ranger	2005	0.848	≈ 2.6	0.3	0.2%	195
Copper, Olympic Dam	2004	5.477	8.887	0.6	2.5%	24
Mineral sands	1997-98	6.7	3.2	2.10	≈ 4%[2]	52
Silver, lead, zinc ore	1997-98	5	1.7	3.02	≈ 30%[3]	10
Gold bullion (doré)	1995-96	12.9	0.00029	44,948	100%[4]	44,948
Gold bullion (doré)	1997-98	13.1	0.00033	39,697	100%[4]	39,697

Table 5.1: Energy intensity of mining and milling in Australia for selected metals and minerals and mines (after [12, 14-18]).

The energy intensity per unit of metal product is dependent on the grade of the ore, that is the concentration of the metal in the ore. For Australia there are energy data for four metal ore mining industries: iron ore, mineral sands, silver-lead-zinc ores, and gold (Table 5.1).

[1] http://www.mii.org/Minerals/photoiron.html.
[2] http://www.chemlink.com.au/titan_rutile.htm, http://invest.vic.gov.au/Key+Sectors/More+Industries/Mineral+Sands.htm.
[3] http://www.pir.sa.gov.au/pages/minerals/commodity/leadzinc.htm:sectID=245&tempID=7.
[4] http://www.e-goldprospecting.com/html/smelting___refining.html, http://www.oxiana.com.au/ProminentHill.asp. *Bullions* are precious metals in the form of bars, wafers, or ingots of .995 purity or finer. A *doré* is an unrefined bar of bullion containing an alloy of gold, silver and impurities, produced through the smelting of gold and silver concentrate, sand or precipitate. Typical impurities include base metals. Doré bars are typically shipped to outside refiners for further processing to almost pure gold, then sold to precious metals dealers, mainly banks and their affiliates (http://www.e-goldprospecting.com/html, http://www.oxiana.com.au/Glossary.asp).

Australian energy intensities are quite comparable to values from the literature, including Storm van Leeuwen [19] (SvL, Figure 5.3).

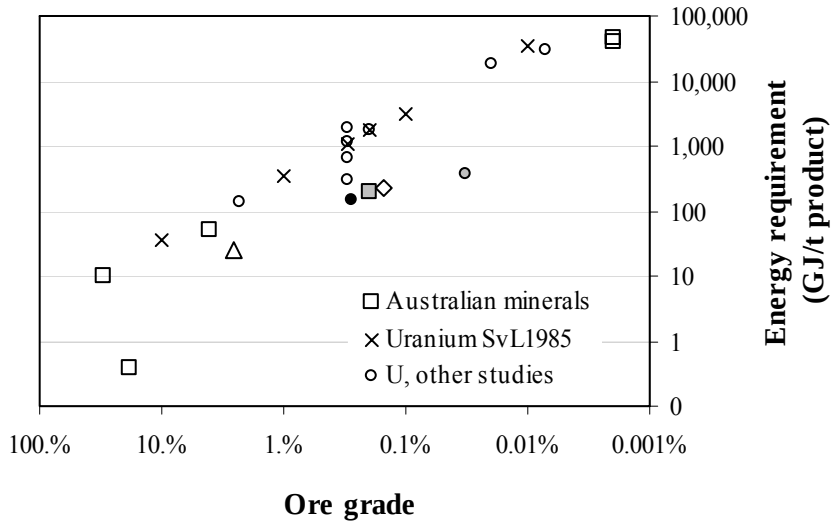


Figure 5.3: Energy intensities for metal ore mining and milling (compiled from data in [12, 14-17, 19-23]). The outliers are the Rössing mine in Namibia (⊙), the Ranger mine in the Northern Territory (▣), and the Beverley mine in South Australia (◇). The triangle (Δ) represents Olympic Dam. In-situ leaching is shown to require less energy than conventional mining (•, [23])

The data depicted in Figure 5.3 leads to a roughly constant energy coefficient per tonne of ore mined. In this analysis we use energy coefficients averaged over values from Australian and international studies (Table 5.2), but we ignore the outlier represented by the Rössing and Ranger mines.[5] These values are in good agreement with the Australian Coal Association's combined figures of 83 kWh_{el} / t ore and 361 kWh_{th} / t ore, respectively.

		Milling	Mining
Electricity	(kWh_{el} / t ore)	25.8	54.3
Thermal energy	(kWh_{th} / t ore)	215.0	126.2

Table 5.2: Energy coefficients for mining and milling used in this work.

[5] The website of the operator of the Ranger mine also lists the ADO consumption of energy electric plant supplying the mine as well as Jabiru township [24]. Based on a daily consumption of 60 tonnes ADO, and a specific energy content of ADO of 45 GJ/t [12], we conclude an annual energy consumption of the electric plant alone of 985 TJ. It is hence not clear whether Ranger's Environment Report [16] covers the entire energy requirement of the mining operations (compare also [17] p. 3 – Comparison with ERDA 76/1).

5.1.2 Ore grade and U_3O_8 recovery (yield)

Based on various sources, and excluding inferred resources, Australia has about just over 1 million tonnes of recoverable reserves of uranium [10, 11, 25]. Ore grades (% U_3O_8) vary significantly, but the average ore grade is 0.045% [25] (Figure 5.4).

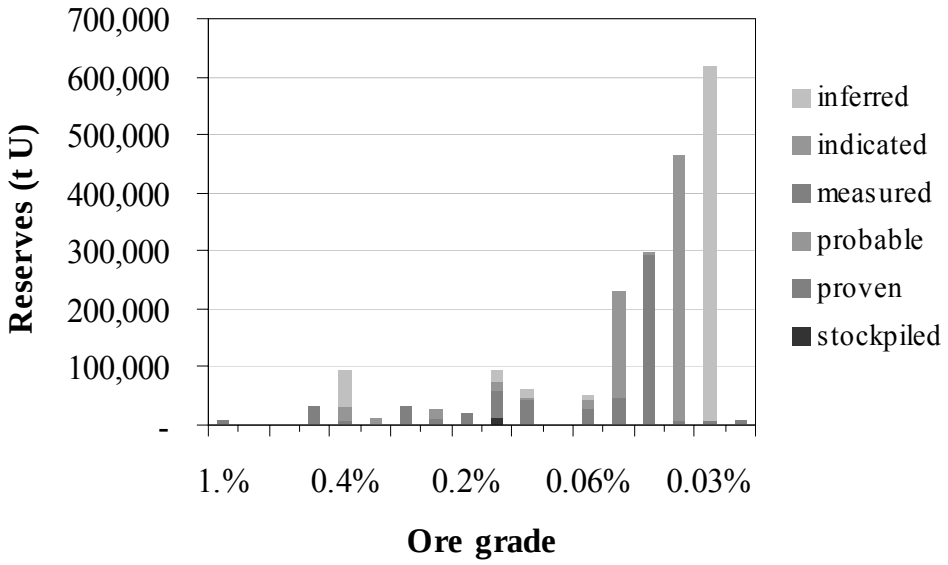


Figure 5.4: Australian uranium reserves and resources [25, 26].

For comparison, the situation in Canadian mines is markedly different: ore grades are more than an order of magnitude higher (the average grade is about 8%), but the overall amount of uranium is lower than that in Australia (Figure 5.5) [10].

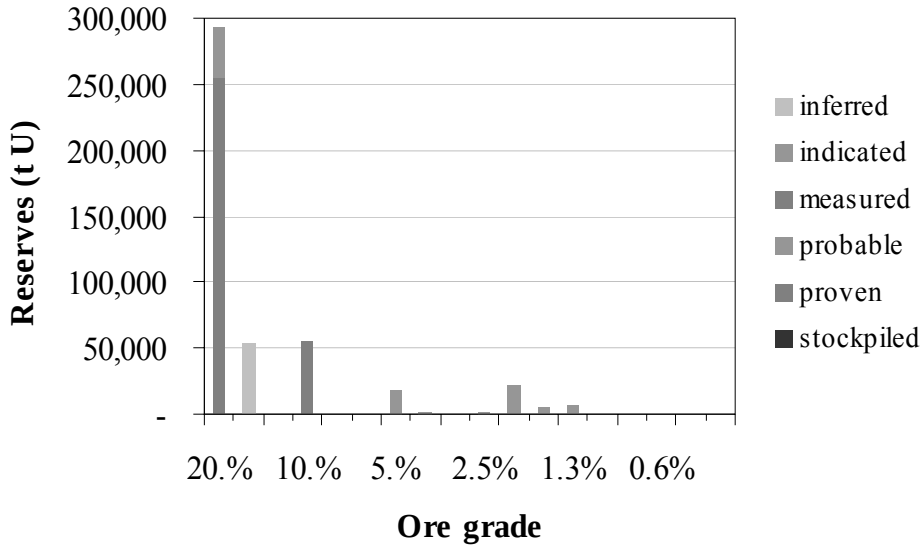


Figure 5.5: Canadian uranium reserves and resources [10].

When calculating the energy requirement and recovery rate for uranium mining, it is important to consider whether any other products are mined simultaneously [27]. This is because the energy requirement must be apportioned (for example by mass) to both primary products and by-products.[6] For example in Australia's Olympic Dam mine, uranium is extracted as a by-product of copper [14, 18, 28, 29].

As a conservative estimate, we assume that all uranium is mined at Australia's Ranger (NT) and Beverley (SA) mines (0.15% U_3O_8), and that this uranium is not accompanied by any primary product or by-product, so that the full mining energy requirement is attributable to uranium. Had we assumed conditions as in the Olympic Dam mine, the ore grade would have been lower (around 0.05%), however most energy requirements would have been attributable to the recovered copper [14, 27, 30]. We apply Storm van Leeuwen and Smith's formula [31] to the respective ore grades (typically 0.15% [25]), resulting in a recovery rate of about 93%. This ore grade happens to be equal to the average ore grade of world resources [32].

5.1.3 Conversion and enrichment of uranium, fuel fabrication

There are currently no facilities in Australia for uranium conversion and enrichment, and for fuel fabrication. Therefore, figures from international studies are adopted for this life-cycle study.

For conversion of UO_2 to UF_6, Rotty and co-workers state requirements of 14.6 MWh_{el} and 396 MWh_{th} per metric ton of uranium ([33] pp. 63-64). Most of the energy needed is in form of natural gas. The more recent estimates of the Australian Coal Association [34] are just over half the above values, which is probably due to technological progress in conversion methods [23]. Rotty et al's figure is the highest in Storm van Leeuwen and Smith's literature review [31], and was taken as a conservative estimate in this report.

For enrichment, Storm van Leeuwen and Smith [31] summarise studies undertaken between 1974 and 2003, averaging 2,630 kWh/SWU for gas diffusion, and 290 kWh/SWU for gas centrifuges. In this study we will use the present mix, which is 30% diffusion and 70% centrifuge.

For fuel fabrication, Storm van Leeuwen and Smith [31] list eleven studies. The figure used in the World Nuclear Association report [17] – 301 MWh_{el} / t U + 2,708 GJ_{th} / t U, giving 5,957 GJ_{th} / t U – is one of the highest in Storm van Leeuwen and Smith's list, and will be used in this report.

[6] BHP Billiton [18] states that "*It is correct to say, for Olympic Dam, that copper, gold, uranium and silver are extracted from one and the same rock body in a simultaneous operation. In the case of the Olympic Dam orebody, we can apportion the energy cost for mining the orebody amongst the four metals based on their relative mass contribution. Once the orebody reaches the surface, energy costs can also be apportioned for grinding. Once the ore then enters the processing circuit the calculation then becomes very process specific - ie at Olympic Dam a lot of the copper goes through flotation, smelting and refining, whereas uranium goes through none of these processes, so the flowsheet needs to be well understood in order to make a complex calculation. At Olympic Dam, our calculations are that for every tonne of ore that we process in its entirety (from mining through to final product, we can allocate 0.012GJ of energy to uranium.*"

In agreement with Storm van Leeuwen and Smith [31], we use process losses between 0.5% and 1% for all processes.

5.1.4 Reactor construction, operation, and decommissioning

There are no commercial nuclear reactors operating in Australia. Therefore, figures from international studies are adopted for this life-cycle study.

For the construction of a LWR and HWR, we discard process analyses and estimations based on national average energy intensities for reasons explained in Section 3, and assume the highest values documented in the literature for input-output analyses (listed in Section 3), which are 4,100 GWh / GW_{el} (LWR, [20]) and 9,800 GWh / GW_{el} (HWR, [35]). We further assume electrical energy to constitute 10% of the energy embodiment [33]. We adjust the construction requirements of reactors with nominal power different to 1 GW_{el} proportional to power.

For the operation of a LWR and HWR, we assume inputs detailed by Hewlett [36] (corresponding to about 10 GWh_{el} of electricity and 270 GWh_{th} of thermal energy annually), with additional heavy water requirements for the HWR (7 GWh_{el} of electricity and 40 GWh_{th} of thermal energy annually). Regarding the lifetime of nuclear power plants Storm van Leeuwen and Smith [31] state that only a small fraction of existing plants has reached 24 full-load years of life. There is however evidence that average load factors have increased to well above 80% over the past decades [37-39]. In this report we assume a lifetime of 35 years at 85% load, giving just under 30 full-load years, which is slightly higher than the estimate of Storm van Leeuwen and Smith [31].

For the decommissioning, we follow the World Nuclear Association [17], and assume that energy requirements are 35% of those for reactor construction.

5.1.5 Reprocessing

The majority of life-cycle analyses of the nuclear fuel cycle assume a once-through mode. Re-processing appears attractive for many reasons, mainly for a) extending the resource base and b) reducing the need for storage and disposal of radioactive waste. Nevertheless, in order to conform with previous assessments, we have restricted the life-cycle assessment for an Australian nuclear industry to a once-through mode.

5.1.6 Waste storage and disposal

At present, low- and intermediate-level wastes are stored at over a hundred sites in Australia [40]. There is at present no final disposal facility, however three potential sites are earmarked on Commonwealth land in the Northern Territory [40, 41].

For storage, we use as a conservative estimate the Australian Coal Association's figure for energy requirements of about 80 MWh_{el} and 600 MWh_{th} per tonne of radioactive material [34].

The Vattenfall [42] and Torness [43] studies are two of the few that consider both storage and disposal. Their assessments yield energy requirements of about 330 MWh_{el} and 120 MWh_{th} per tonne of HLW, and about 24 MWh_{el} and 1 MWh_{th} per tonne of ILW/LLW. These figures need to be qualified with the fact that both the Vattenfall [42] and Torness [43] studies

- are based on process analysis and may be affected by truncation errors;
- omit the waste from mining, milling, conversion, enrichment and fuel fabrication facilities;
- base their final disposal calculation on hypothetical scenarios [44].

We apply these intensities to

- the waste from fuel fabrication (small, HLW),
- the spent fuel (about 25 tonnes HLW per GWy),
- contaminated structural material (about 13 tonnes HLW annually [45]), and
- active waste from the decommissioned plant (about 10,000 tonnes each ILW and LLW [44, 45]).

For the enrichment tails (omitted in the Torness study), we take the figures for re-conversion, conditioning and disposal stated by Storm van Leeuwen and Smith [31]. These figures are slightly higher than those for the conversion stage, and appear as a realistic estimate.

We chose not to apply the figures stated by Storm van Leeuwen and Smith [31] for storage, disposal, and for returning the mine site to "green fields" condition, because their suggested procedure differs from most of the descriptions in the open literature, and is not practised by the industry in Australia [46-48]. However, we did not investigate whether current mining practices are adequate in isolating radioactivity from tailings from the environment, since this was outside the scope of this work. We do not apply Storm van Leeuwen and Smith's figures solely because we regard them as outliers in a statistical sense. Instead, we assume current industry practices, so that the energy requirements for the treatment of mine tailings are included in the energy figures for Australian mining (Table 5.1).

5.1.7 Transport

In agreement with the scenario in Section 4, we assume that

- U_3O_8 is transported to Australian ports (1,000 km rail @ 0.6 MJ/ntkm),
- shipped to Europe and the USA (20,000 km ship @ 0.4 MJ/ntkm + 500 km rail @ 0.6 MJ/ntkm) for conversion, enrichment and fuel fabrication,
- the fuel rods shipped back (20,000 km @ 0.4 MJ/ntkm + 500 km road @ 1.7 MJ/ntkm),
- trucked to Australian reactors (1,000 km @ 1.7 MJ/ntkm), and
- all wastes trucked to storage and disposal sites (1,000 km @ 1.7 MJ/ntkm).

5.2 Fuel cycle calculation

The first set of calculations represents the nuclear fuel cycle, including all energy-generating and -consuming systems. These calculations proceed naturally along the stages of the nuclear fuel stream, starting with a prescribed demand of electricity, and successively calculating the requirements of thermal heat, reactor fuel, enriched uranium, natural uranium, and uranium ore. Table 5.3 lists all successive stages.

	Calculation stage	Variable / equation	Values and units
1	Power demand	P	3,370 MW_{el}
2	Annual net electricity output	$E_{net} = P \times 8760$ hr	25,000 $GWh_{el}\ y^{-1}$
3	Distribution loss	λ_d	variable, 3-9% ([42] p. 18)
4	Annual electricity output at plant	$E = E_{net} / (1 - \lambda_d)$	$GWh_{el}\ y^{-1}$
5	Thermal efficiency	ε_{th}	30% (conventional turbine stage)
6	Reactor heat output into turbine	$H_{net} = E / \varepsilon_{th}$	$GWh_{th}\ y^{-1}$
7	Reactor heat loss	λ_r	variable, %
8	Heat from fission	$H = H_{net} / (1 - \lambda_r)$	$GWh_{th}\ y^{-1}$
9	Energy content of fissile isotopes	ρ_{iso}	24,500 $GWh_{th}\ t^{-1}$
10	Mass of all burnt isotopes	$m_{iso} = H_{net} / \rho_{iso}$	t isotopes y^{-1}
11	Burn-up	β	extraction of heat from fuel before re-load, $MWd_{th}\ t^{-1}$
12	Mass of loaded $^{235}_{92}U$	$m_{235U,l} = m_{iso}\ \rho_{iso}\ \eta_{235U} / \beta$	t $^{235}_{92}U\ y^{-1}$
13	Fabrication loss	λ_f	variable, %
14	Mass of enriched $^{235}_{92}U$	$m_{235U,e} = m_{235U,l} / (1 - \lambda_f)$	t $^{235}_{92}U\ y^{-1}$
15	Enrichment	η_{235U}	% $^{235}_{92}U$
16	Mass of enriched U	$m_{U,e} = m_{235U,e} / \eta_{235U}$	t U y^{-1}
17	Tails assay	x_t	variable, %
18	Uranium feed	$m_{U,f}$; SWU calculation[7]	t U y^{-1}
19	Conversion loss	λ_c	variable, %
20	Mass of net mill output	$m_{U,net} = m_{U,f} / (1 - \lambda_c)$ / 0.848 t U per t U_3O_8	t $U_3O_8\ y^{-1}$
21	Milling loss	λ_m	0.5 %
22	Mass of mill output	$m_{U,net} = m_{U,f} / (1 - \lambda_m)$	t $U_3O_8\ y^{-1}$
23	Recovery rate (yield)	ρ ; regression formula	%
24	Mass of U_3O_8 in ore	$m_U = m_{U,net} / \rho$	t $U_3O_8\ y^{-1}$
25	Ore grade	γ ; regression formula	%, ‰ (t ore per t U_3O_8)
26	Mass of ore	$m_{ore} = m_U / \gamma$	t U ore y^{-1}

Table 5.3: Calculating the nuclear fuel cycle.

[7] A Separative Work Unit is defined as $SWU = P\ V(x_p) + T\ V(x_t) - F\ V(x_f)$, where the value function is $V(x) = (1 - 2x) \ln[(1 - x)/x]$, P, T and $F = P + T$ are the masses, and x_p, x_t and $x_f = P/F\ x_t + T/F\ x_f$ are the assays (concentrations) of product, tails and feed, respectively ([33] pp. 65-66).

The second set of calculations determines the energy requirements for the fuel and waste streams (Table 5.4).

Stage	Unit	Electricity	Thermal energy
Mining	$GWh_{el/th}$/t ore	5.43E-5	1.26E-4
Milling	$GWh_{el/th}$/t ore	2.58E-5	2.15E-4
Conversion	$GWh_{el/th}$/t $_{U3O8}$	1.46E-2	3.96E-1
Enrichment (70%centrifuge)	$GWh_{el/th}$/tSWU	9.29E-1	2.53E-1
Fuel fabrication	$GWh_{el/th}$/t ^{235}U	3.01E-1	7.52E-1
Construction	$GWh_{el/th}/GW_{el}$	1.37E+2	3.69E+3
Operation	$GWh_{el/th}/GWy_{el}$	1.00E+1	2.70E+2
Decommissioning	$GWh_{el/th}/GW_{el}$	1.37E+1	3.69E+2
Storage	$GWh_{el/th}$/t waste	8.00E-2	6.00E-1
ILW/LLW disposal	$GWh_{el/th}$/t waste	2.44E-2	1.09E-3
HLW disposal	$GWh_{el/th}$/t waste	3.29E-1	1.19E-1
Depleted uranium	$GWh_{el/th}$/t U	2.49E-2	4.47E-1
Mine clean-up	$GWh_{el/th}$/t tailings	-	-
Road transport	$GWh_{el/th}$/ntkm	0	4.72E-7
Rail transport	$GWh_{el/th}$/ntkm	0	1.67E-7
Ship transport	$GWh_{el/th}$/ntkm	0	1.11E-7

Table 5.4: Energy coefficients used in this work.

Next, critical parameters and assumptions have to be specified for the nuclear energy system and its components, as well as the background economy. Table 5.5 gives a summary for parameters for our "baseline" case. These parameters represent conservative estimates: For example

- most economies have lower carbon-coefficients than a pure black-coal economy,
- reactor lifetimes are longer than 35 years when extended [36],
- thermal efficiencies of modern steam turbines can be well above 30%,
- burn-ups can be stretched beyond 55 MWd_{th} / kgU,[8]
- future enrichment will only use centrifuges, and
- uranium-bearing ores are often mined for other metals as well.

[8] Long-term objectives for breeder fuel cycles are 150-200 MWd_{th}/kg [49].

Variable	Unit	Baseline
Reactor type	1 - LWR; 2 – HWR	1
Economy-wide GHG intensity, thermal, black coal economy	kg CO_2-e/kWh	0.31
Economy-wide GHG intensity, electrical, black coal economy	kg/kWh	1.0
Economy-wide electricity ratio		*3.10*
Nominal power	MW	1,300
Load factor		85% [37]
Lifetime	years	35
Distribution losses		5%
Thermal efficiency		30%
Heat loss factor		2%
Energy content of fissile isotopes	GWh_{th} / t heavy metals	24,500
Burn-up (LWR/HWR)	MWd_{th} / kgU	*45 / 11*
Fabrication loss		1%
Enrichment (LWR/HWR)		3.5% / 0.72%
Enrichment method		30% Df, 70% Ce
Tails assay		0.25%
Conversion loss		0.5%
Milling loss		0.5%
Recovery rate	Function of ore grade	*93.1%*
Ore grade		0.15%

Table 5.5: Parameters for the baseline case (figures in *italics* are derived using formulae in Table 5.3).

5.3 Spreadsheet tool

The spreadsheet tool adheres closely to the stage-wise life-cycle calculation described in the previous Section. In addition, it contains a list of parameters which the user can modify in order to evaluate scenarios.

The material and energy flows in the calculation are represented by coloured fields (Figure 5.6). Starting at the top right corner, ore (ochre) is mined and U_3O_8 (grey) extracted. Further towards the left, U_3O_8 is converted, enriched, and fabricated into fuel. During the reactor operation, it undergoes fission, creating heat (red). The heat is converted into electricity (yellow), which is finally transmitted to the consumer for use in appliances and lighting (☼). Each stage requires energy, which is represented by the top row of orange fields. Once again, starting from the right, energy is required for mining, milling, conversion, enrichment, fuel fabrication, construction, operation and decommissioning. At the bottom of the diagram are the associated waste flows (pink), calculated as the remainders of the top-row material flows. All waste ultimately needs to be returned to the environment (≡). Waste management requires energy, which is specified in the bottom rows of orange fields. All stages require transport energy, which is specified in the blue fields.

The overall results of the calculation appear in the top left frame. A breakdown of these results appears just to the left of the orange energy requirements block. The entire calculation is specified by the parameters and equations in Table 5.3, Table 5.4, and Table 5.5. The parameters block appears below the overall results block, on the left hand side of the screen.

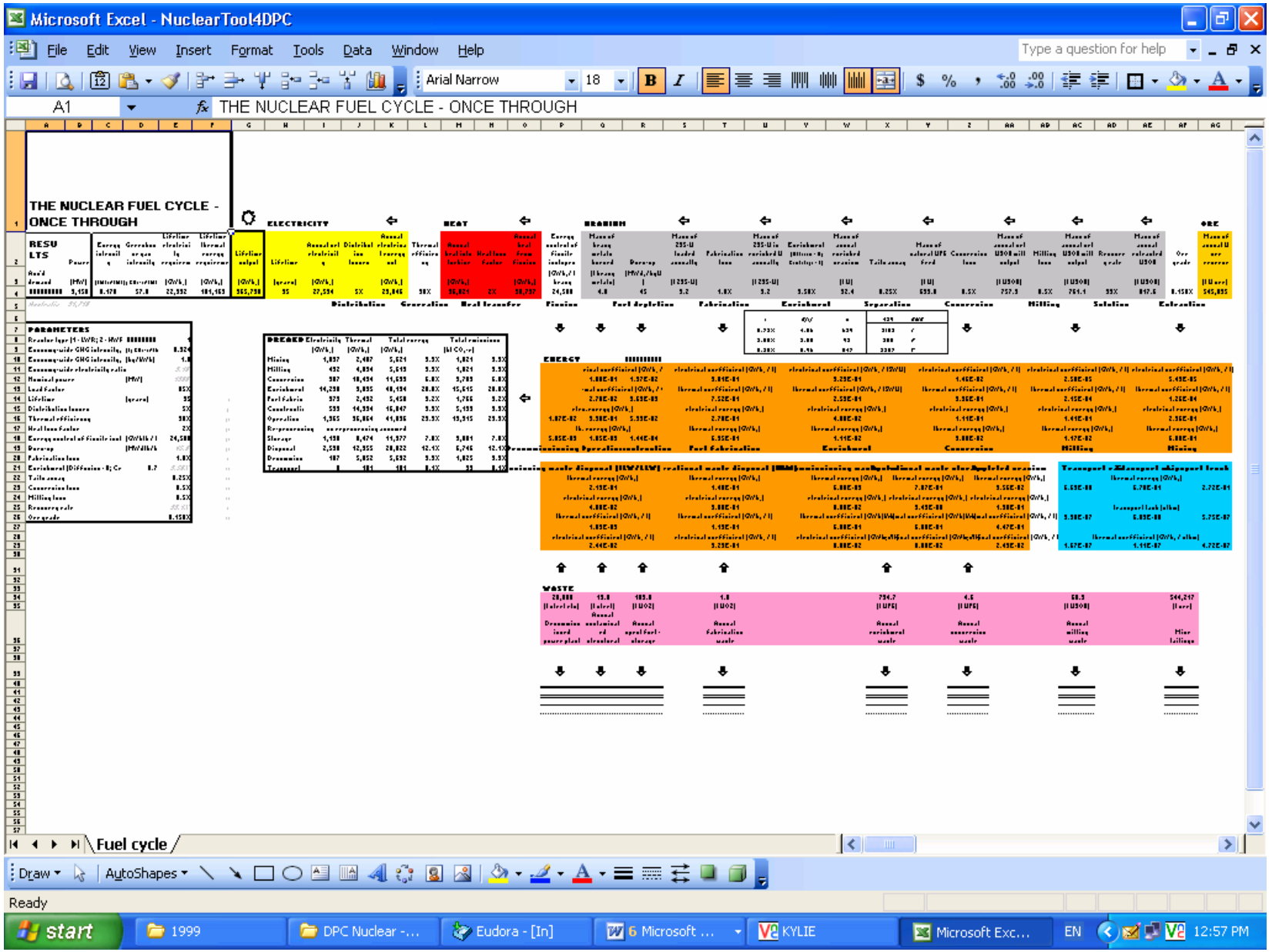


Figure 5.6: Overview of the nuclear fuel cycle calculator.

Starting from the top right, the material cycle distinguishes ore mining and milling, conversion, enrichment and fuel fabrication. Between these stages, recovery rates, losses, separative work, and tails are specified (Figure 5.7).

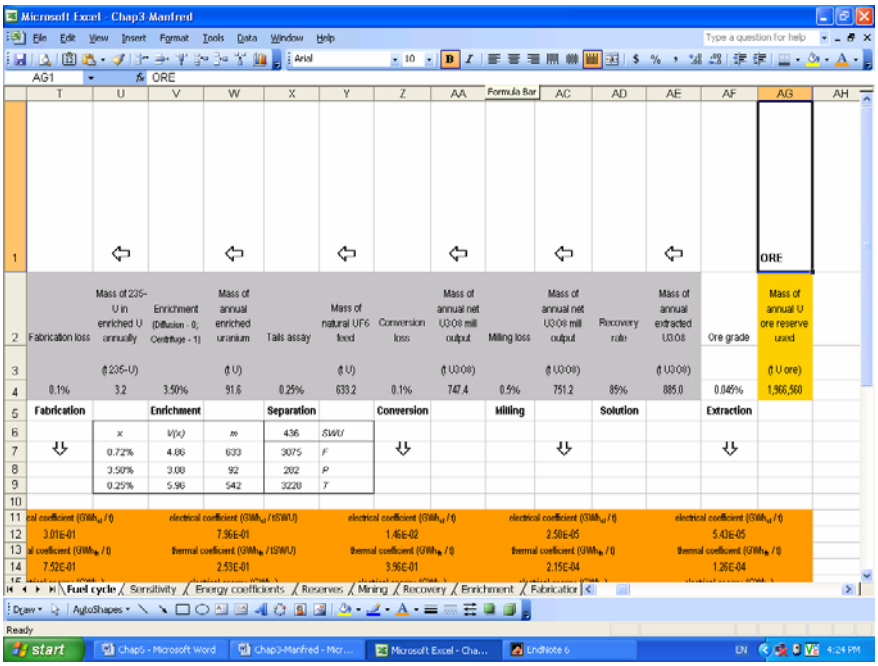


Figure 5.7: Calculation of ore and uranium mass flows.

Following, to the left, the burn-up is calculated, followed by the heat generated inside the reactor core, the electricity generated in the turbine, and distributed to the consumer. Once again, each stage interspersed with specifications of parameters and losses (Figure 5.8).

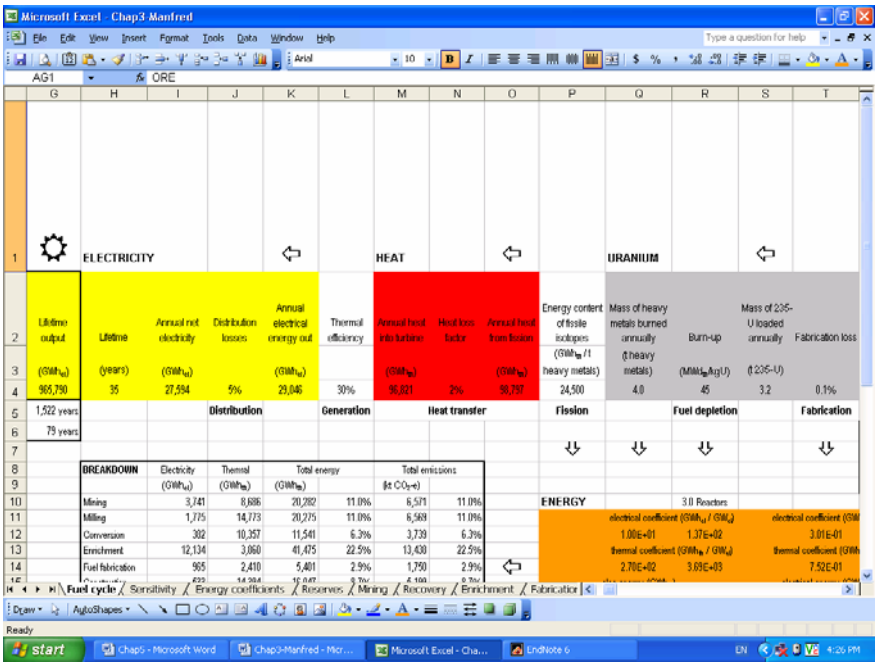


Figure 5.8: Calculation of burn-up, heat and electricity generation.

Each of these stages produces waste, which is calculated simply as a remainder (Figure 5.9).

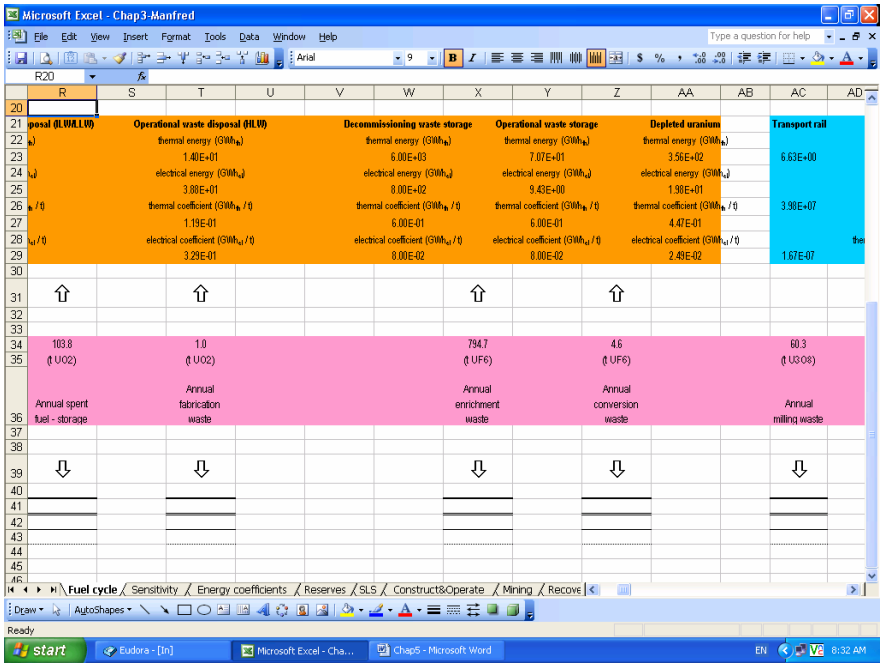


Figure 5.9: Calculation of waste mass flows.

Each stage requires operational and transport energy, which is calculated from coefficients in Table 5.4. These coefficients are re-stated in the orange fields (Figure 5.10).

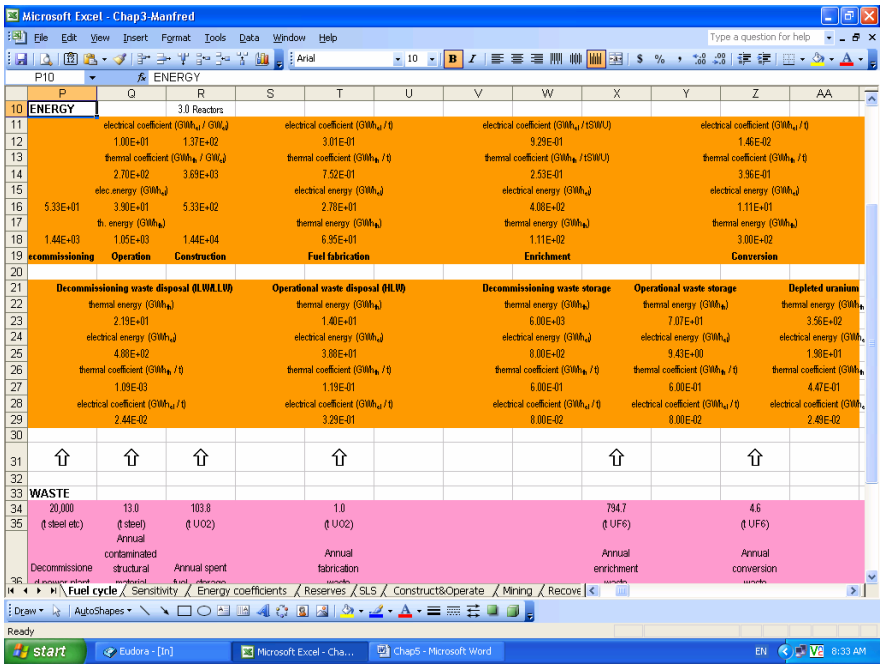


Figure 5.10: Calculation of energy requirements.

The energy requirements are summed over all stages, distinguishing electricity and thermal energy, and the result converted into greenhouse gas emissions, using greenhouse gas contents of fuels as assumed in the parameter list. All results are tabulated in the breakdown table (Figure 5.11).

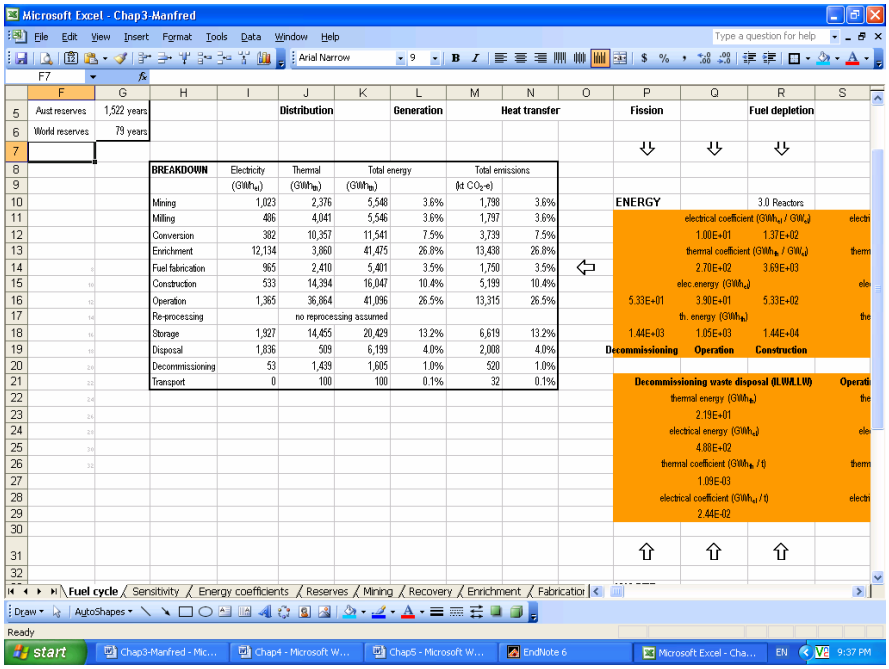


Figure 5.11: Breakdown of energy and greenhouse gas requirements.

Results are aggregated and converted into energy and greenhouse gas intensities in the top left results block (Figure 5.12).

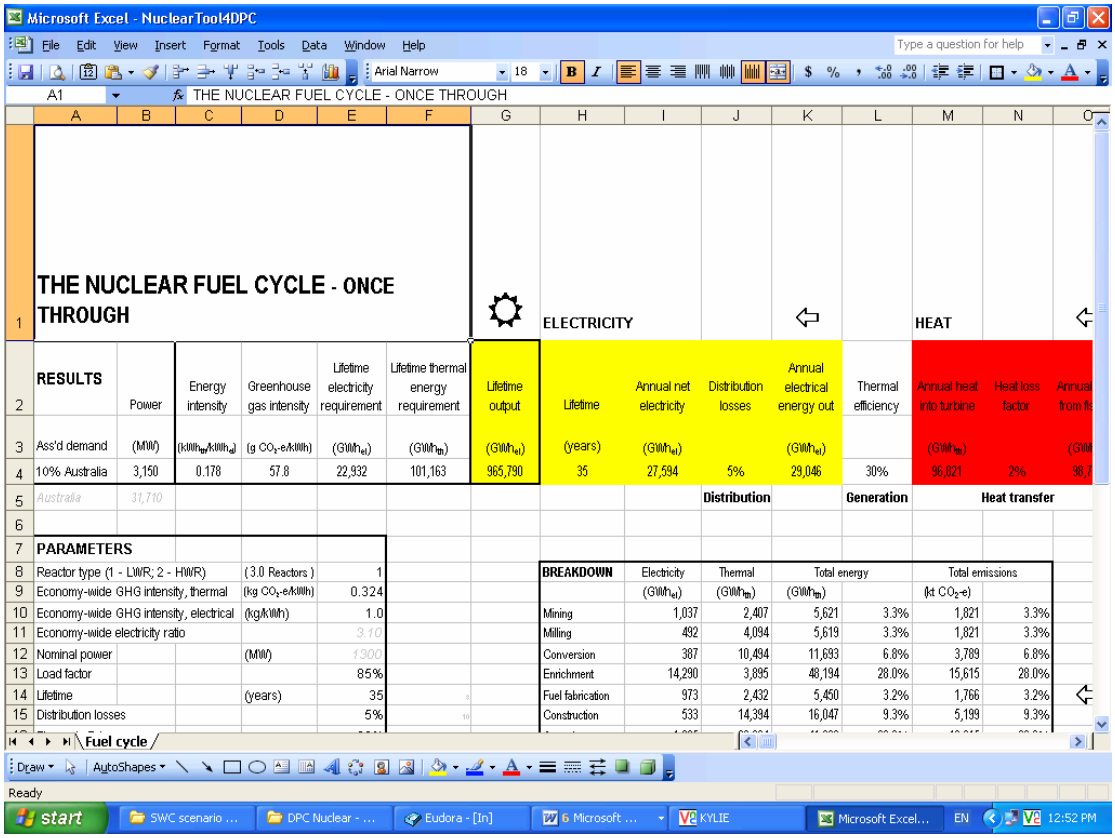
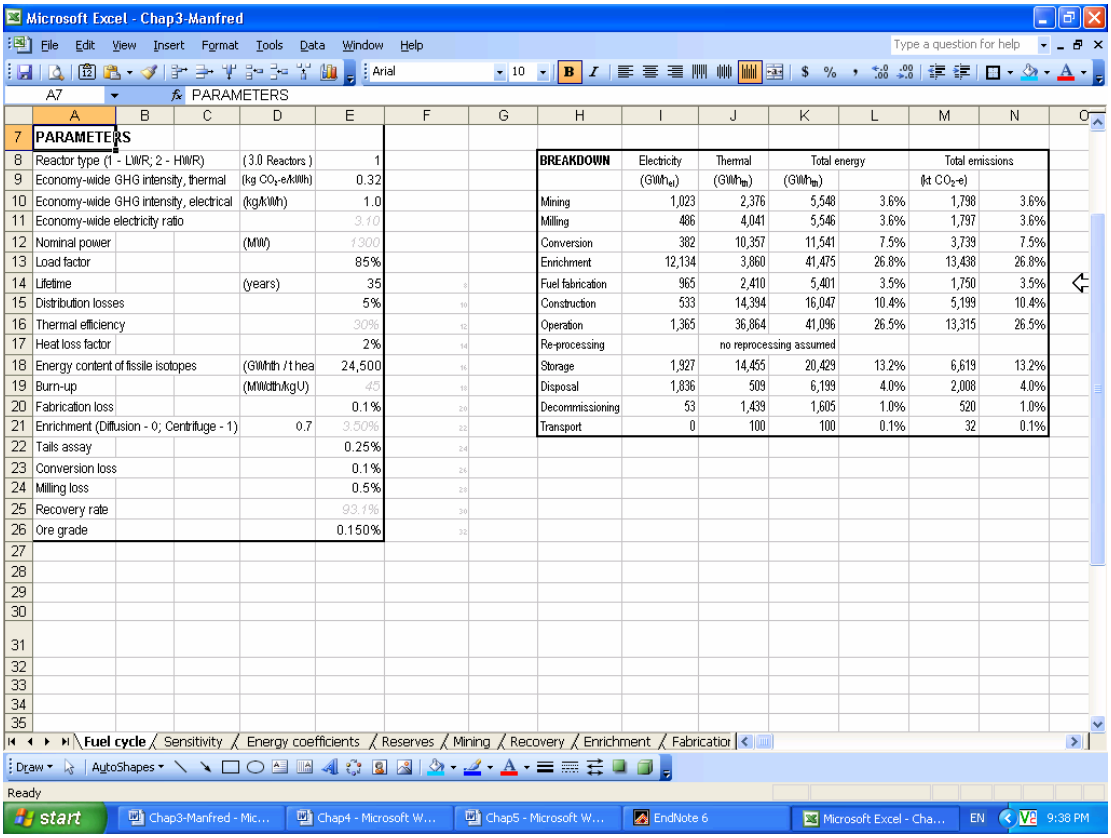


Figure 5.12: Overall results: energy and greenhouse gas intensities, total energy and greenhouse gas requirements.

Finally, the entire calculation is driven by the assumed parameters (Figure 5.13). The baseline case is listed in Table 5.5. Figures in grey italics are either fixed or calculated from other parameters.



	A	B	C	D	E
7	**PARAMETERS**				
8	Reactor type (1 - LWR; 2 - HWR)			(3.0 Reactors)	1
9	Economy-wide GHG intensity, thermal			(kg CO_2-e/kWh)	0.32
10	Economy-wide GHG intensity, electrical			(kg/kWh)	1.0
11	Economy-wide electricity ratio				3.10
12	Nominal power			(MW)	1300
13	Load factor				85%
14	Lifetime			(years)	35
15	Distribution losses				5%
16	Thermal efficiency				30%
17	Heat loss factor				2%
18	Energy content of fissile isotopes			(GWdth / t hea	24,500
19	Burn-up			(MWdth/kgU)	45
20	Fabrication loss				0.1%
21	Enrichment (Diffusion - 0; Centrifuge - 1)			0.7	3.50%
22	Tails assay				0.25%
23	Conversion loss				0.1%
24	Milling loss				0.5%
25	Recovery rate				93.1%
26	Ore grade				0.150%

BREAKDOWN	Electricity (GWh_{el})	Thermal (GWh_{th})	Total energy (GWh_{th})		Total emissions (kt CO_2-e)	
Mining	1,023	2,376	5,548	3.6%	1,798	3.6%
Milling	486	4,041	5,546	3.6%	1,797	3.6%
Conversion	382	10,357	11,541	7.5%	3,739	7.5%
Enrichment	12,134	3,860	41,475	26.8%	13,438	26.8%
Fuel fabrication	965	2,410	5,401	3.5%	1,750	3.5%
Construction	533	14,394	16,047	10.4%	5,199	10.4%
Operation	1,365	36,864	41,096	26.5%	13,315	26.5%
Re-processing		no reprocessing assumed				
Storage	1,927	14,455	20,429	13.2%	6,619	13.2%
Disposal	1,836	509	6,199	4.0%	2,008	4.0%
Decommissioning	53	1,439	1,605	1.0%	520	1.0%
Transport	0	100	100	0.1%	32	0.1%

Figure 5.13: Parameters for the nuclear fuel cycle.

5.4 Results and sensitivity analysis

The relationships in Table 5.3 and the parameters in Table 5.5 were used to enumerate the mass flow in the nuclear fuel cycle for Australia. These results flows were compared with Vattenfall's Environmental Product Declaration [42] (Table 5.6).

Material type	Unit	This study	Vattenfall [42]	Comments
Ore mined	t ore	1,557,750	818,065	21% in-situ leaching in [42]
Mine tailings	t ore	1,557,049	n.a.	
U_3O_8 extracted	t U_3O_8	592	522	
Milling waste	t U_3O_8	109	107	
Converted $_{UF6}$	t UF_6	729	655	
Conversion waste	t UF_6	0.7	0.006	
Enriched uranium	t UF_6	105	100	
Tails	t UF_6	624	706	
Fuel fabrication waste	t UO_2	0.08	-	Not considered in [42]
Reactor fuel	t fuel	82	77	
Spent reactor fuel	t heavy metals	82	77	

Table 5.6: Mass flow in the Australian and Swedish nuclear fuel cycle.

Considering that the two systems differ slightly in their ore provenance, grade and mining method, enrichment method, tails assay, reactor types, burn-up and load factors, the agreement between the two data sets is satisfactory.

In order to demonstrate the influence of the parameters in Table 5.5, we carry out a number of sensitivity analyses (compare with [50]). We vary the parameters according to scenarios in Table 5.7 (LWR) and Table 5.8 (HWR), yielding results in Table 5.9 (LWR) and Table 5.10 (HWR). Upper and lower bounds were derived from the sensitivity analysis, however the best and worst-case scenarios were excluded from these from these bounds, because they are considered unlikely.

Scenario	Load factor	Lifetime	Distribution loss	Burn-up	Enrichment mix	Enrichment	Tails assay	Ore grade	Economy-wide GHG intensity
Baseline	85%	35	5%	45	0.7	3.50%	0.25%	0.15%	0.324
1980s USA	75%								
1990s Japan	80%								
near-full load	90%								
early decommissioning		25							
life extension		45							
industry customer			2.5%						
customer mix			7.5%						
household customer			10.0%						
frequent re-load				35					
infrequent re-load				55					
100% diffusion enrichment					0				
100% centrifuge enrichment					1				
low-level enrichment						3%			
high-level enrichment						4%			
Expensive uranium							0.20%		
Cheap uranium							0.30%		
Canadian ore								2%	
Low-grade shale								0.01%	
Brown coal economy									0.342
Natural gas economy									0.184
90% renewable/nuclear economy									0.054
Best case	90%	45	2.5%	55	1	3%	0.30%	2%	0.054
Worst case	75%	25	10%	35	0	4%	0.20%	0.01%	0.342

Table 5.7: Sensitivity scenarios for the LWR.

Scenario	Load factor	Lifetime	Distribution loss	Burn-up	Enrichment mix	Enrichment	Tails assay	Ore grade	Economy-wide GHG intensity
Baseline	85%	35	5%	9.3	0.7	0.72%	0.25%	0.15%	0.324
1970s USA	75%								
1990s Japan	80%								
near-full load	90%								
early decommissioning		25							
life extension		45							
industry customer			2.5%						
customer mix			7.5%						
household customer			10.0%						
frequent re-load				7.2					
infrequent re-load				11.3					
Canadian ore								2%	
Low-grade shale								0.01%	
Brown coal economy									0.342
Natural gas economy									0.184
90% renewable/nuclear economy									0.054
Best case	90%	45	2.5%	11.3				2%	0.054
Worst case	75%	25	10%	7.2				0.01%	0.342

Table 5.8: Sensitivity scenarios for the HWR.

Variable	Unit	Scenario	Variation	Energy intensity (kWh_{th} / kWh_{el})	(Sensitivity)	GHG intensity (g CO_2-e / kWh_{el})	(Sensitivity)	Energy payback time (years)
		Baseline		0.178		57.8		6.3
Load factor	%	1980s USA	75%	0.187	(5%)	60.6	(5%)	6.6
		1990s Japan	80%	0.182	(2%)	59.1	(2%)	6.4
		near-full load	90%	0.175	-(2%)	56.6	-(2%)	6.1
Lifetime	years	early decommissioning	25	0.191	(7%)	62.0	(7%)	6.7
		life extension	45	0.171	-(4%)	55.4	-(4%)	6.0
Distribution loss	%	industry customer	2.5%	0.174	-(2%)	56.4	-(2%)	6.1
		customer mix	7.5%	0.183	(3%)	59.2	(3%)	6.4
		household customer	10.0%	0.188	(5%)	60.8	(5%)	6.6
Burn-up	$GW_{th}d/tU$	frequent re-load	35	0.208	(16%)	67.2	(16%)	7.3
		infrequent re-load	55	0.160	-(10%)	51.8	-(10%)	5.6
Enrichment method		100% diffusion enrichment	0	0.252	(41%)	81.5	(41%)	8.8
		100% centrifuge enrichment	1	0.147	-(18%)	47.6	-(18%)	5.2
Enrichment	%	low-level enrichment	3%	0.162	-(9%)	52.3	-(9%)	5.7
		high-level enrichment	4%	0.195	(10%)	63.3	(10%)	6.9
Tails assay	%	Expensive uranium	0.2%	0.181	(2%)	58.7	(2%)	6.4
		Cheap uranium	0.3%	0.178	(0%)	57.6	(0%)	6.2
Ore grade	%	Canadian ore	2.5%	0.168	-(6%)	54.3	-(6%)	5.9
		Low-grade shale	0.01%	0.402	(125%)	130.2	(125%)	14.1
GHG intensity of economy	kg CO_2-e/kWh_{th}	Brown coal economy	0.342	0.178	(0%)	61.0	(6%)	6.3
		Natural gas economy	0.184	0.178	(0%)	32.7	-(43%)	6.3
		90% renewable/nuclear economy	0.054	0.178	(0%)	9.6	-(83%)	6.3
		Best case		0.106	-(41%)	5.7	-(90%)	3.7
		Worst case		0.726	(307%)	248.4	(330%)	25.5

Table 5.9: Results and sensitivity analysis for the LWR.

Variable	Unit	Scenario	Variation	Energy intensity (kWh_{th} / kWh_{el})	(Sensitivity)	GHG intensity (g CO_2-e / kWh_{el})	(Sensitivity)	Energy payback time (years)
		Baseline		0.197		63.8		6.9
Load factor	%	1970s USA	75%	0.211	(7%)	68.4	(7%)	7.4
		1990s Japan	80%	0.204	(3%)	66.0	(3%)	7.2
		near-full load	90%	0.191	-(3%)	61.9	-(3%)	6.7
Lifetime	years	early decommissioning	25	0.223	(13%)	72.1	(13%)	7.8
		life extension	45	0.183	-(7%)	59.2	-(7%)	6.4
Distribution loss	%	industry customer	2.5%	0.192	-(2%)	62.3	-(2%)	6.8
		customer mix	7.5%	0.202	(3%)	65.5	(3%)	7.1
		household customer	10.0%	0.207	(5%)	67.2	(5%)	7.3
Burn-up	$GW_{th}d/tU$	frequent re-load	7.2	0.220	(12%)	71.4	(12%)	7.8
		infrequent re-load	11.3	0.183	-(7%)	59.2	-(7%)	6.4
Ore grade	%	Canadian ore	2.0%	0.189	-(4%)	61.4	-(4%)	6.7
		Low-grade shale	0.01%	0.353	(79%)	114.5	(79%)	12.4
GHG intensity of economy	kg CO_2-e/kWh_{th}	Brown coal economy	0.342	0.197	(0%)	67.4	(6%)	6.9
		Natural gas economy	0.184	0.197	(0%)	36.2	-(43%)	6.9
		90% renewable/nuclear economy	0.054	0.197	(0%)	10.6	-(83%)	6.9
		Best case		0.153	-(22%)	8.3	-(87%)	5.4
		Worst case		0.490	(149%)	167.6	(163%)	17.2

Table 5.10: Results and sensitivity analysis for the HWR.

The results of the sensitivity analysis confirm the results of the multiple regression in Section 3.13. For the case of the light water reactor (Table 5.7 and Table 5.9) energy intensities are around 0.18 kWh_{th}/kWh_{el}, while greenhouse gas intensities are around 60 g CO_2-e/kWh_{el}. Energy payback times are around 6½ years. Both energy and greenhouse gas intensities show substantial scatter when parameters are varied. The ore grade and enrichment method are the most important influencing parameters. Moreover, the greenhouse gas intensity is significantly influenced by the greenhouse gas intensity of the background economy.

The greenhouse gas intensities for the best-case scenario agree with those obtained for the low-carbon economies Switzerland (Dones et al [38]) and Japan (Hondo, Uchiyama and co-workers [51, 52]).

For the case of the heavy water reactor (Table 5.8 and Table 5.10) energy intensities are around 0.20 kWh_{th}/kWh_{el}, while greenhouse gas intensities are around 65 g CO_2-e/kWh_{el}. Energy payback times are around 7 years. Once again, both energy and greenhouse gas intensities show substantial scatter when parameters are varied. Enrichment does not play a role since the HWR is fuelled with natural uranium. The ore grade is the most important influencing parameter. Once again, the greenhouse gas intensity is significantly influenced by the greenhouse gas intensity of the background economy.

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6 Energy and greenhouse gas emissions in the life cycle of selected non-nuclear power technologies: a literature review

In this section a review is presented of the energy and greenhouse performance of the main non-nuclear electricity technologies in an Australian context. As in earlier sections, we report on the *energy* and *greenhouse gas intensity*, that is the ratio of the primary energy consumed, or greenhouse gases emitted for all activities involved in producing electricity, per unit of electrical energy supplied to the grid over the lifetime of the electricity supply. The current Australian average electricity mix is used for all calculations of embodied energy and emissions for the technologies. The results would be different if for example renewable energy is used to supply the process electricity required for new renewable technologies.

The energy and greenhouse intensities of the following non-nuclear electricity technologies are calculated and discussed in this section:

- black coal fired (sub-critical and supercritical)
- brown coal fired
- natural gas fired (open and combined cycle)
- wind turbines,
- solar photovoltaic (PV) systems, and
- hydroelectricity (run-of-river).

It is assumed that the coal-fired and combined cycle natural gas generation will supply "firm" capacity, that is, the plant can supply all of the required capacity when running at its typical utilisation rate (assumed to be 80% [1]). For open cycle natural gas, which is assumed to be peaking capacity, a lower capacity factor is used. For the renewable cases, in the absence of energy storage devices, this is not assumed, since the variable nature of renewables is implicit (see Sections 2.6 to 2.8). It is assumed that in both fossil and renewable cases the peak power can be met, with varying capacity factors based on the different technologies and their parameters. For all cases, grid losses of 5% are included, as for the nuclear energy case, so that energy and greenhouse intensities refer to delivered rather than sent-out electricity.

Due to their different nature and operating characteristics, lifetimes for these non-nuclear technologies can vary considerably (compare Section 2.3). In the following, typical literature values of lifetimes will be assumed and their performance in energy and greenhouse terms is clearly dependent on these assumptions. Such values, together with efficiency, and capacity figures will be used to form a typical scenario describing the performance of a new installation of each type of technology. High and low scenarios are also developed.

6.1 Current fossil-fired electricity in Australia

In terms of total Australian electricity *production* in 2003-04, from a total on-grid capacity of 45 GW_{el}, 232 GWh in total were generated, and 205 TWh were supplied for final *consumption* (compare Section 5.1), with an average capacity utilisation of about 60% [2]. There are approximately 42 GW of installed or under-construction fossil generation plant in Australia. The breakdown of this capacity by fuel and technology type is given in Table 6.1 [3]. Black coal dominates the fuel mix with about 254 GW_{el} or 57% of total capacity, representing about 59% of total thermal electricity generation [2]. The dominant conversion technology is steam turbine (open Rankine cycle) which comprises more than three-quarters of total fossil electrical capacity.

It is instructive to view the installation history of this fossil capacity since 1960 (Figure 6.1). New capacity was established relatively quickly in two periods: the late 1960s to early 1970s, and then the late 1970s to mid 1980s, the latter period resulting in an additional 15,000 MW_{el}. Since then there has been a much more gradual increase in new capacity. There is much new capacity proposed or under development, about 70% of which is planned to use natural gas as fuel [4].

	Steam turbine	Gas turbine	Gas Turbine Combined Cycle	Co-generation	Reciprocating Engine	*Total fuel*	%-age fuel
Black coal	23,616			441		*24,057*	57%
Brown coal	6,560					*6,560*	16%
Natural gas	1,541	4,736	2,755	1,114	146	*10,292*	25%
Other various (gas, oil, bagasse)	225	401		116	261	*1,003*	2%
Total technology	*31,942*	*5,137*	*2,755*	*1,671*	*407*	**41,912**	
%-age technology	76%	12%	7%	4%	1%		

Table 6.1: Fossil generation capacity in Australia (GW_{el}, operating or under construction) [3].

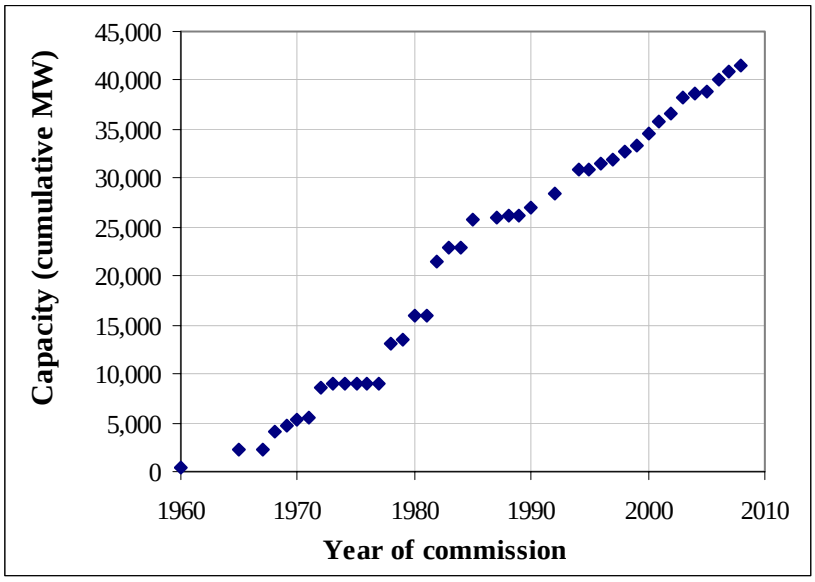

Figure 6.1: Resulting cumulative capacity (MW_{el}) since 1960 from nominal commissioning year for fossil generation capacity in Australia and (major upgrades not included) [3].

6.1.1 Thermal efficiencies of current Australian fossil-fired electricity

The full chain emissions from fossil generation capacity are dominated by the emissions related to the fuel extraction, preparation and combustion, with combustion emissions being most important, as discussed further below. In this section we list recent combustion-only operational energy efficiencies and process-based LCA greenhouse emissions for major Australian power stations.

The Cooperative Research Centre for Coal in Sustainable Society (CCSD)[1] has documented the performance of many aspects of electricity generation in Australia. CCSD data on the major power stations in NSW, QLD and Victoria are listed in Table 6.2 [5-7]. The majority of the generation types are subcritical pulverised fuel (PF) using coal. CCSD has undertaken process-based life cycle analyses of generation with a system boundary that usually includes construction-related energy and emissions. Major contributions usually include energy and emissions related to mining and extraction in general, transportation of the fuels, and their combustion. In NSW power stations the majority of coal is delivered by conveyor, with a typical distance of less than 10 km (see Table 7 [7]). Except for a few rail delivery modes, most of the remaining coal in NSW is typically transported 5-10 km by road. In Queensland the approximate coal transport profiles are Callide (conveyor 5 km), Gladstone (rail 315 km), Swanbank (1/3 by road ~40 km, 2/3 by rail 195 km), Stanwell (rail 200 km), and Tarong (most by conveyor 20 km) [6]. In Victoria, the brown coal is sourced within ~5 km of the power stations and most coal was delivered by conveyor [5].

State	Station name	Type	Capacity (MW_{el})	Comm. year	Specific energy (GJ/t)	Average thermal eff. (%)	Capacity factor (%)	GHG emissions (kg CO_2-e/MWh)
NSW	Eraring	Black, PF	2640	1982	24.3	36.4	63%	879
NSW	Bayswater	Black PF	2640	1984	21.5	35.3	66%	888
NSW	*Bayswater [1]*	*Black PF*	*2640*	*1984*	*23.9*	*36.1*	*70%*	*932*
NSW	Liddell	Black PF	2000	1971	20.8	32.7	53%	963
NSW	Vales Point B	Black PF	1320	1978	23.8	35.0	56%	911
NSW	Mt Piper	Black PF	1320	1992	24.7	36.0	76%	871
NSW	Wallerawang	Black PF	1000	1976	26.0	32.1	57%	924
NSW	Munmorah	Black PF	600	1969	26.3	33.1	20%	952
QLD	Tarong	Black PF	1400	1984-86	20.5	34.3	85%	918
QLD	Gladstone	Black PF	1680	1976-81	21.2	35.0	67%	932
QLD	Stanwell	Black PF	1400	1993-96	27.1	36.4	76%	882
QLD	Callide B	Black PF	700	1988-89	20.0	34.4	91%	985
QLD	Swanbank A	Black PF	408	1966-69	25.3	31.0	-	962
QLD	Swanbank B	Black *	500	1970-73	25.3	31.0	-	962
QLD	Wivenhoe	Pumped hydro	500	1984	-	-	-	-
VIC	Loy Tang A	Brown PF	2000	1984-87	8.1	31.1	97%	1217
VIC	Loy Tang B	Brown PF	1000	1993-96	8.1	30.8	82%	1291
VIC	Hazelwood	Brown PF	1600	1964-71	8.7	25.8	82%	1338
VIC	Yallourn	Brown PF	1450	1973-82	6.5	27.9	74%	1301
VIC	Jeeralang A/B	NG turbine	466	1979-80	39.3 (MJ/m^3)	24.8/26.7	5%	699
VIC	Newport D	NG boiler	500	1980	39.3 (MJ/m^3)	34.9	21%	524

Table 6.2: List of major (> 400 MW_{el}) on-grid generators in NSW, Queensland and Victoria in 2001, their thermal efficiencies (sent-out) and greenhouse intensities from a process-based LCA [5-7]. Separate figures for Bayswater are also listed, from [1]. All figures are on a high heating value basis (HHV). Snowy Hydro and smaller generators are excluded. * Coal seam methane as fuel.

[1] See http://www.ccsd.biz

The sent-out thermal efficiency of conventional PF coal power stations is dependent on many factors including: the age of equipment, coal characteristics, cooling method, ambient and cooling water temperatures, load fluctuations, and auxiliary equipment required such as pollution filters, fuel preparation and ash disposal. These factors in turn can vary from year to year. The steam cycle and generation equipment are likely to have the most important impact on the overall thermal efficiency, but without very detailed data on all these aspects for all stations, a full separation of the contributions to the greenhouse intensities cannot be made. The thermal efficiency figures in Table 6.2 must therefore be considered as operational averages. For comparison, in 1997-98 the average grid thermal efficiency of generation was 34.5%, and for Australia as a whole was 33.1% [1].

The separate figures for Bayswater are indicative of the uncertainty and fluctuations in power station performance, which typically result in variations of the greenhouse intensity of up to 5%, as noted in CCSD documents [1, 7]. The thermal efficiencies of NSW and Queensland power stations are comparable both in average and range, having similar average technology ages and fuel quality figures. The emissions intensity of Victorian base load generation is approximately 40% higher. The typical capacity factor figures listed in Table 6.2 show that even "base-load" coal-fired capacity factors vary considerably, and are very high (>85%) for only a few power stations.

Total greenhouse intensities (by CCSD LCA method) by state, together with the transmission and distribution losses in the national grid are shown in Table 6.3. These are the aggregate figures and also incorporate other generation capacity not listed in Table 6.2. Data for Western Australia's south west interconnected system are also included. Note the relatively low capacity factors in all but Queensland. As would be expected, the greenhouse intensities of the delivered electricity from the state grids show a similar relationship to the sent-out greenhouse intensities of Table 6.2.

Grid	**Capacity factor (%)**	**Emissions intensity after transmission, in kg CO_2-e/MWh (losses %)**	**Emissions intensity after distribution, in kg CO_2-e/MWh (losses %)**
NSW	59.7	974 * (2.7%)	1031 * (5.5%)
Queensland	62.1	1028 (5.3%)	1088 (5.5%)
Victoria	73.5	1402 (2.5%)	1503 (6.7%)
WA (south west)	40.1 (2000-01)	(inc. in transmission)	1018 (8.1%)

Table 6.3: State grid greenhouse intensities including contributions from transmission and distribution losses [5-8]. * Excluding Snowy Hydro System.

Although natural gas fired capacity on the national grid is increasing rapidly, as shown above, grid-based generation is still dominated by coal fired capacity. Natural gas generation is discussed in more detail in Section 6.3.

6.1.2 International thermal efficiencies for fossil generation

In 1997-98 the Australian Greenhouse Office (AGO) commissioned Sinclair Knight Merz (SKM), as "integrating consultants" to develop a framework for four independent fossil fuel specific consultancies within which current Australian best practice in fossil-fuelled power

generation could be assessed in a common format [9]. This process produced the list of current Australian best practice thermal efficiencies and corresponding *combustion-only* greenhouse emission rates for different technologies given in Table 6.4. These figures are broadly consistent with those in Tables 6.2 and 6.3, if a little lower in terms of emission rates, particularly since fuel extraction emissions are generally not included. However, the thermal efficiency stated for Victorian brown coal at 27.7% is significantly lower than the figures of ~31% for the Loy Yang power stations shown in Table 6.2, though the corresponding emission rates are similar.

Fuel	**Thermal efficiency %**	**Emission rate (kg CO_2/MWh)**
Black Coal	36.8	861
Brown Coal		
Victorian	27.7	1220
South Australian	32.0	1080
Natural Gas		
Steam	35.9	510
Open cycle gas turbine	35.1	537
Combined cycle GT	40.0	451
Diesel	37.0	681

Table 6.4: Australian best practice (ABP) in 1997-98 for thermal efficiency (sent-out) and *combustion only* emission rates on a high heating value basis [9].

The SKM/AGO report also provides world's best practice efficiencies for fossil equipment, corrected for any significant differences to Australian conditions (Table 6.5) [9]. These efficiencies are plotted in Figure 6.2 and indicate that for subcritical steam plants, Australian plants perform close to the world's best. However, Australian plants lag somewhat behind best practice for supercritical plants, of which there aren't many in Australia (see Section 6.2.2). Australia's combined cycle gas-fired technologies efficiencies are also in general substantially lower than world's best practice. Note that the separate curves in Figure 6.2 for coal and natural gas technologies are due to the lower emissions content per unit of energy of natural gas. Although the emissions content per unit of energy for black and brown coal plant are similar for the same thermal efficiency, due to the high moisture content in brown coal, it is easier to achieve higher conversion efficiencies with black coal conversion cycles.

Australia's general lower than best practice performance can be explained mainly by the relative age of the generation stock and Australia's relatively inexpensive fuel costs providing smaller incentives for maximising conversion efficiencies, particular in terms of natural gas technologies, compared with European gas prices.

Finally, for comparison the AGO's Program Guidelines for Generator Efficiency Standards [10] in 2000 stipulated the following best practice new plant thermal efficiencies (sent-out, HHV):

- Black coal plant 42%
- Brown coal plant 31.4%
- Natural gas combined cycle plant 52%.

Technology	WBP Efficiency HHV Basis	Cycle
Black Coal (440 MW_{el})	41.7%	Supercritical
Black Coal (405 MW_{el})	37.7%	Subcritical
Brown Coal (850 MW_{el})	31.4%	Supercritical
Brown Coal (500 MW_{el})	29%	Subcritical
Gas Open Cycle (50 MW_{el})	37.6%	Open cycle GT
Gas Open Cycle (200-300 MW_{el})	35.5%	Open cycle GT
Gas Combined Cycle (200 MW_{el})	46.7%	Combined Cycle GT
Gas Combined Cycle (500 MW_{el})	52.0%	Combined Cycle GT
Gas Steam Cycle (230 MW_{el})	37.7%	Subcritical

Table 6.5: World's best practice (WBP) for thermal efficiency (sent-out) on a high heating value (HHV) basis for selected fossil generation technologies [9].

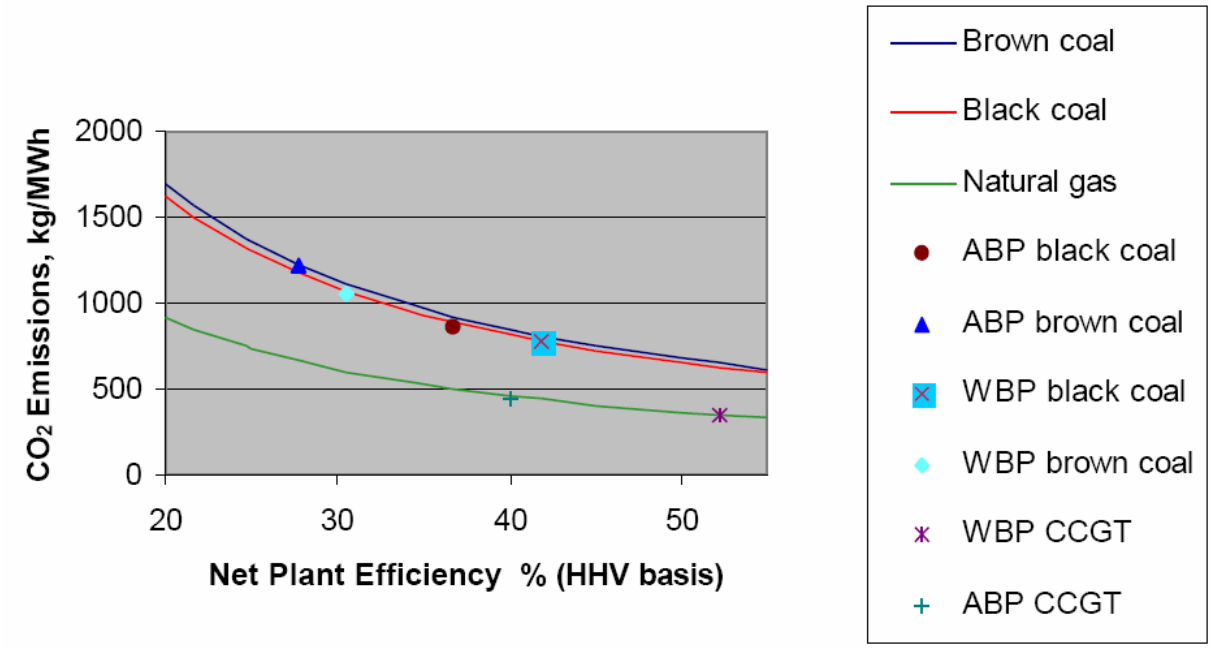

Figure 6.2: Comparison between world's best practice (WBP) and Australian best practice (ABP) for direct combustion emissions versus thermal efficiency for selected fossil generation technologies [9].

6.2 Black coal fired electricity

6.2.1 Black coal fired – conventional subcritical

About 3.5 GW of new black coal capacity has been commissioned in Australia in the last 10 years. The standard or conventional black coal generation is technology is pulverised fuel (PF) operating at subcritical steam conditions [1]. Coal is finely milled and then injected into large furnaces connected via a series of heat exchanges to the steam cycle. Conversion efficiencies (sent-out) of up to 37.7% can be achieved (Table 6.5) typically comprising a boiler efficiency of 90%, 44% for the turbo generator and 5% auxiliary losses for the plant [9]. Key characteristics of conventional PF generation are shown in Table 6.6, for the case of

Bayswater Power Station in the Hunter Valley in NSW commissioned in 1984-85 [1]. A service life of 30 years was expected but is likely to be longer for most plants, as demonstrated by the trend for substantial upgrades and turbine replacement [11].

Parameter	Details
Total capacity	2640 MW_{el} (4 x 660 MW_{el})
Utilisation / generation	Approximately 70%, or 15,500 GWh/a *sent-out* to the grid
Efficiency	36.1%, overall thermal efficiency sent-out
Ancillary electricity	5.2% of total generated is use for pumps, control equipment, milling, filtering etc.
Steam conditions	16.6 MPa and 540 °C
Fuel source	6.4 Mt/a of black coal from open cut mines in the Hunter Valley. 99% of the carbon in the coal is converted to CO_2 in the boiler.
Flue gases	At 130-150°C, inc. CO_2, CO, NO_x, N_20 and SO_x and CH_4.

Table 6.6: Typical characteristics, conversion processes and efficiencies for Bayswater, a conventional subcritical PF using black coal, from a CCSD case study [1].

In order to develop standard scenarios for describing new best-practice subcritical and supercritical black coal generation, a standard fuel source is required. Key aspects are the moisture and ash contents. Moisture in the coal reduces the efficiency due to loss of latent heat in the flue gas, typically the efficiency reduces at 0.15% for a 1% moisture increase [9]. Ash content increases of 1% will typically reduce station efficiencies by 0.025%. Algorithms are commonly developed to account for these changes in full characteristics, but detailed breakdowns of the coal components are required [9, 12]. Sample characteristics are available in the Generator Efficiency Standards calculator [13]. Notwithstanding the fuel variations, the fuel characteristics given in below (Table 6.7) will be used in the calculations presented here. Note that these fuel characteristics are similar to those use in the CCSD case study on conventional PF black coal generation (see Table 1.4 [1]).

Coal properties	Figure
C_{daf} (carbon in coal, dry ash-free basis) (%)	84.3
Fly ash proportion of total ash (%)	90
Carbon in fly ash (%)	2
Furnace ash proportion of total ash (%)	10
Carbon in furnace ash (%)	5
Carbon in fuel (%) (% by difference)	60.1
Sulfur in fuel (%)	0.6
Nitrogen in fuel (%)	1.8
Hydrogen in fuel (%)	5.3
Oxygen in fuel (%)	7.9
Moisture in fuel (%)	7.5
A_{as} (Ash in fuel) (%)	21.2
$Q_{gr,v,as}$ (gross calorific value of the fuel at constant volume, as-fired) (MJ/kg)	24.4
Coal CO_2 emission factor (kg CO_2/kg Coal)	2.19
Coal CH_4 emission factor (g CH_4/kg Coal)	0.0220
Coal N_2O emission factor (g N_2O/kg Coal)	0.0095

Table 6.7: Black coal properties and main combustion products for a nominal plant [12-14]. The coal is Hunter Valley Black Coal (from Appendix F2.2, p. 84, Draft GES [12]).

The main components of the greenhouse and net energy performance of a new conventional black coal fired plant operating at best practice efficiency are shown in Table 6.8. Other than CO_2 emitted from combustion, methane from mining is the only other important contribution. Note that degradation of capacity is not considered here, though there are considerable allowances for performance degradation in Appendix B of the draft generator standards [12].

	Calculation stage	Variable / equation	Values (range), units & comments
1	Power delivered to grid	P	1000 MW_{el}
2	Load factor	λ	variable, 70% (60-80%)
3	Annual net electricity output	$E_{net} = P \times \lambda \times 8760$	$GWh_{el}\ y^{-1}$
4	Grid losses (total)	λ_d	variable, 5% (3%-9%)
5	Annual electricity sent-out	$E = E_{net} / (1 - \lambda_d)$	$GWh_{el}\ y^{-1}$
6	Sent-out efficiency	$\varepsilon_{so} = \varepsilon_g \times \varepsilon_b \times (1 - \chi_{aux})$	variable, calculated
7	Auxiliary load fraction	$\chi_{aux} = P_A / P_G$	5%, ratio auxiliary load to total generated
8	**Generator efficiency**	ε_g	**variable, 44% (42-45%)**
9	**Boiler efficiency**	ε_b	**variable, 90% (89-91%)**
10	Nominal power	$P_{nom} = P / \lambda / (1 - \lambda_d) (1 - \chi_{aux})$	MW_{el} , variable calculated
11	Lifetime	T	variable, 30 years (25-35)
12	Coal transport distance	X	variable, 20 km(5-200), assumed by rail
13	Gross specific energy of coal	Q_{gr}	24.4 MJ/kg (data)
14	Thermal energy required	$Q_{th} = E / \varepsilon_{so}$	$GWh_{th}\ y^{-1}$
15	Coal required	$M = Q_{th} / (Q_{gr} / 3.6) \times 1000 \times T$	tonnes
16	Coal emissions factor	EF	2.19 kg CO_2-e / kg coal, calc. from coal data, negligible CH_4 and N_20 emissions from combustion (Section 7.3, [15])
17	**Coal GHG emissions**	$GHG_{coal} = M \times EF$	tonnes CO_2-e, mainly CO_2 from combustion
18	**Mining CH_4 emissions**	$GHG_{fugitive} = M \times EF_{fugitive}$	~45 kg CO_2-e / t coal (10-200), Table 6.9
19	Mining (energy & GHG)	eg. $E_{mining} = M \times F_{mine}$	$GWh_{th/el}$ & tonnes CO_2-e, factors from Table 6.3 of EcoInvent report [16]
20	Transport (energy & GHG)	eg. $GHG_{trans} = M \times X \times EF_{trans}$	GWh_{th} & tonnes CO_2-e, rail data from Table 5.4, diesel fuel emission factor
21	Construction (energy & GHG)	*Eg.* E_{cons} = *inventory* × IO energy & GHG coefficients	$GWh_{th/el}$ & tonnes CO_2-e, various material inventories and in the worst case from Hill and Walford [1, 17]
22	Decommissioning	*Eg.* $E_{decom} = E_{cons} \times 0.05$	Assumed to be 5% of construction

Table 6.8: Calculation steps and main assumptions in the energy and emission calculations for new conventional black coal generation. Base case values are given and low to high ranges are shown in parentheses. Important contributions are shown in bold.

Various fugitive methane emission factors are given in Table 6.9 for different types of mining. For clarity, the most important parameters for the analysis are listed in Table 6.10 for base, high and low cases. The high case includes all contributions that will raise the energy and greenhouse intensities, and the low case *vice versa*. These cases are very much extreme, though they are quite feasible given the range of values possible. Other important general parameters and definitions used are the same as for the nuclear energy analysis presented in Section 5.

Coal	CH_4 kg / t coal	CO_2-e kg / t coal
Gassy underground mines: NSW	17.21	361.4
Gassy underground mines: QLD	17.43	366.0
Less gassy underground mines	0.54	11.3
Open cut mines: NSW	**2.17 ***	**45.5**
Open cut mines: Queensland	0.81	17.1
Open cut mines: Tasmania	0.68	14.2

Table 6.9: Fugitive emissions from the production of coal from various sources [18]. Bold shows the base case. These are similar to more detailed calculations undertaken by the AGO [19]. * EcoInvent use a figure of 2.7 for their Australia calculations (p. 48 [16]).

Main parameters	Base	High	Low
Load factor (%)	80%	70%	90%
Grid losses (%)	5%	9%	3%
Turbine efficiency (%)	44%	42%	45%
Boiler efficiency (%)	90%	89%	91%
Lifetime (years)	30	25	35
Coal emissions factor (kg CO_2-e / kg coal)	2.19	2.3	2.1
CH_4 emissions from mining (kg CO_2-e / t coal)	45.5	**200**	10
Coal transport distance by rail (km)	20	200	5

Table 6.10: Main analysis parameters for each case for conventional PF generation from black coal. All high parameters will raise the energy and greenhouse intensities. The bold figure for high methane emissions from mining assumes 50% open cut and 50% underground mining of the source coal.

The breakdown of the base case results are shown in Table 6.11. As expected the main contributions are due to combustion of the fuel, and the methane emissions from coal mining [1]. Emissions from energy use for mining amount to 2.9 kt CO_2-e or 1.2%. The results confirm that transport (nominally by rail for 20 km) and construction energy use and emissions are negligible compared to those associated with the fuel. Construction energy and emissions, estimated for masses of concrete, steel and copper outlined in [1] combined with the embodied energy and emissions figures shown in Table 3.9 of this report, were calculated for comparison. However, construction energy requirements were taken from Hill and Walford [17], and although these are an order of magnitude higher than those calculated from a basic material inventory and IO materials coefficient, construction still represents a very small part of the total energy and greenhouse intensities. Uchiyama et al [20] give a detailed breakdown of non-combustion energy use for a 1000 MW_{el} plant with capacity factor of 75% operating for 30 years. Energy for construction is only about 5% of the annual fuel energy, so over the lifetime is very small, which is consistent with the results here. Operational energy however is also about 5% of the annual fuel energy use, and is included here as the parasitic power requirement. Hence the overall energy and emissions intensities are not very sensitive to the chosen capacity factor and plant lifetime.

Breakdown	Electricity (GWh_{el})	Thermal (GWh_{th})	Total energy (GWh_{th})	(%)	Total emissions (kt CO_2-e)	(%)
Mining	1,942	3,035	9,055	1.21%	7,878	3.18%
Transport	0	362	362	0.05%	102	0.04%
Construction	651	2,632	4,650	0.62%	1,506	0.61%
Combustion coal	0	735,331	735,331	98.09%	237,822	96.13%
Decommissioning	33	132	232	0.03%	75	0.03%

Table 6.11: Total full chain energy and emissions for the base case for black coal.

Case	**Energy intensity** (kWh_{th}/kWh_{el})	**Greenhouse gas intensity** (g CO_2-e/kWh)	**Lifetime output** (GWh_{el})	**Comment**
Base	2.85	941	262,800	3% of emissions are from mining
High	3.17	1170	219,000	9% of emissions are from mining
Low	2.70	843	306,600	

Table 6.12: Summary of life cycle energy and greenhouse intensities for black coal electricity generation for the three cases with 1000 MW_{el} effective power delivered.

The base case result of 941 g CO_2-e/kWh is consistent with other figures such as from the CISS Case Study B1 which has 932 g CO_2-e/kWh (though grid losses are not included there [1]), Tahara et al 916 g CO_2-e/kWh [21], Uchiyama et al [20] of 989 g CO_2-e/kWh and the AGO Workbooks [18] of 985 g CO_2-e/kWh. The results here are also consistent with those for the European countries included in the EcoInvent report with a range of ~900-1000 g CO_2-e/kWh (Figure 6.3 [16]).Combustion emissions are typically more than 95% of the total life cycle emissions.

The spreadsheet tool ("Black coal" worksheet) can be used to explore the sensitivities. The base case should be regarded as applying for new generation with best practices conversion efficiencies, under typical NSW coal conditions, and with 5% generation losses. The high case, which assumes 50% of coal is sourced from gassy underground mines with resulting higher methane emissions and slightly lower conversion efficiencies, may be considered a worst case scenario. Similarly the low case assumes very optimistic, but feasible conditions, all in combination. The high and low estimates therefore represent very conservative bounds to the most likely or typical case.

6.2.2 Black coal fired – supercritical

Supercritical plants operate at steam temperatures of ~550 °C and pressures of at least 23 MPa [22]. So-called ultra- or advanced-supercritical (ASC) plants operate at temperatures of up to ~650 °C and pressures of up to 35 MPa. Advanced supercritical conversion technologies require major changes throughout plants so these are not usually suitable for retrofitting to existing generation capacity. However supercritical operating conditions are proven and cost effective with further potential for improvement. Supercritical generation equipment is now regarded as standard, though the uptake of this technology is Australia has been relatively slow [23]. Advanced materials, in turbine blades for example, are required to operate at the more extreme cycle conditions. Despite the use of high strength specialised alloys, the projected costs of supercritical capacity are not significantly higher than subcritical capacity (Table 6.13). Hence in the following calculations, the embodied energy and emissions for supercritical plant will be assumed to be the same as for subcritical plant. The typical minimum size of supercritical plant is for units being greater than about 400 MW_{el}. A summary of the performance characteristics of supercritical black coal technologies is given in Table 6.13.

Of the currently operating black coal-fired steam turbine plants in Australia, about 1740 MW_{el} capacity is existing supercritical technology in two stations, with a further 750 MW_{el} supercritical plant under construction at a third. All these plants are in Queensland [24]. An 800 MW_{el} supercritical plant is currently proposed for Western Australia. The current best performing supercritical plant in Australia, at Callide, achieves a sent-out efficiency of 39.4 % (Appendix A, Table 1 [22]).

Technology	Year	Steam temperature (°C)	Steam pressure (MPa)	Net thermal efficiency (%)	Life cycle emissions intensity (g CO_2-e/kWh)	Capital cost ($/$kW_{el}$)
Subcritical PF base case	2000	540	16.6	37.6	941 [a]	1023
Subcritical PF base case	2050	540	16.6	39	911 [a]	950
Supercritical PF	2002	~560	23	41	788	1151
Supercritical PF	2010	~560	25	43		1062
Supercritical PF	2030	~560	25	45		960
Ultra-supercritical PF	2005	630	30	45.3	716	
Ultra-supercritical PF	2015	600-700	30-40	52		950

Table 6.13: Performance characteristics of supercritical black coal technologies and a base case subcritical plant for comparison. Capital costs are indicative only. Various sources have been used: Tables 1 & 2 [25], Pages 39-40 and Tables 5.1, 5.3, 5.5 [23], Table 2.2 [26], Appendix A [22], [a] this work.

For the analysis here, the main difference for the supercritical case is that higher conversion efficiencies are assumed than the base case convention PF sent-out efficiency of 37.6%. A current best practice sent-out efficiency of 41% will be assumed, corresponding to a turbine efficiency of 48% (47-49%) in Table 6.10. This leads to sent-out efficiencies of 39.7%, 41%, and 42.4 % in the high, base and low emissions cases respectively. All other aspects of the analysis are the same as for the subcritical base case, and the high and low variants with the above efficiencies. Construction energy and emissions are assumed to be the same as for the subcritical case.

Breakdown	Electricity	Thermal	Total energy		Total emissions	
	(GWh_{el})	(GWh_{th})	(GWh_{th})	(%)	(kt CO_2-e)	(%)
Mining	1,780	2,782	8,300	1.21%	7,221	3.18%
Transport	0	332	332	0.05%	94	0.04%
Construction	651	2,632	4,650	0.68%	1,506	0.66%
Combustion coal	0	674, 054	674, 054	98.03%	218,005	96.08%
Decommissioning	33	132	232	0.03%	75	0.03%

Table 6.14: Full chain energy and emissions for the base case for supercritical black coal.

Case	**Energy intensity**	**Greenhouse gas intensity**	**Lifetime output**	**Comment**
	(kWh_{th}/kWh_{el})	(g CO_2-e/kWh)	(GWh_{el})	
Base	2.62	863	262,800	3% of emissions are from mining
High	2.84	1046	219,000	9% of emissions are from mining
Low	2.48	774	306,600	1.7% of emissions are from mining

Table 6.15: Summary of life cycle energy and greenhouse intensities for supercritical black coal electricity generation for the three cases with 1000 MW_{el} effective power delivered.

The results above again show a typical (base) case together with extreme bounds. Supercritical operation for the base case of 863 g CO_2-e/kWh leads to about an 8% reduction in emissions intensity over the sub-critical case of 942 g CO_2-e/kWh. The results are comparable with an earlier CCSD figures of 842 g CO_2-e/kWh [1], but the figure of 788 g CO_2-e/kWh stated in Table 5.5 [23] is significantly lower. Part of the difference may be due to the smaller system boundary employed in the CCSD LCA studies, and the absence of grid losses in their analysis, together with a more conservative (lower) figure used here for the turbine efficiency of subcritical plant.

6.3 Brown coal fired electricity

Brown coal (lignite) fired electricity mainly occurs in Victoria, with some 6560 GW_{el} installed capacity. CCSD studies find that for the brown coal case, fuel combustion causes ~99% of total life cycle emissions [5]. There are negligible methane emissions from Victorian open cut brown coal mining, and since the transport distances to the power stations are short, transport-related emissions are even smaller than for the case of black coal in the Hunter Valley. Though very small, transport emissions are included for completeness as if they occurred by rail over an assumed distance of 2 km. Energy required for brown coal mining is estimated using European EcoInvent data [16], but is a also small contribution to total energy and emissions. This contribution should be considered as worst case scenario. Construction energy requirements will be assumed to be similar to those for black coal, except scaled by the typical capital cost ratio of brown to black coal of $1300 / $1000 per kW_{el} [25].

Notwithstanding the fuel variations from station to station (eg. Table 7 [5]), the fuel characteristics given in Table 6.16 below will be used in the calculations presented here, as a typical average. The high moisture content of the lignite (typically ~60% or more) leads to the energy content of the fuel being around one third of that of black coal of the same mass. Brown coal boiler efficiencies are typically 66% to 75 %, leading to a best practice sent-out efficiency of 31.4% (Page 85 [9]), which is the generation efficiency target for new brown coal plant [12, 15]. This corresponds to a turbine efficiency of 44% and a 5% station auxiliary power requirement. Actual brown coal thermal efficiencies for eight Victorian plants range from 32% down to less than 20%, with a median figure of about 27.5%, some of which are shown in Table 6.2 [9].

Coal properties	**Figure**
C_{daf} (carbon in coal, dry ash-free basis) (%)	69.8
Fly ash proportion of total ash (%)	90
Carbon in fly ash (%)	18
Furnace ash proportion of total ash (%)	10
Carbon in furnace ash (%)	18
Carbon in fuel (%) (% by difference)	26.3
Sulfur in fuel (%)	0.4
Nitrogen in fuel (%)	0.6
Hydrogen in fuel (%)	4.9
Oxygen in fuel (%)	24.3
Moisture in fuel (%)	61.5
A_{as} (Ash in fuel) (%)	0.8
$Q_{gr,v,as}$ (gross calorific value of the fuel at constant volume, as-fired) (MJ/kg)	10.2
Coal CO_2 emission factor (kg CO_2/kg Coal)	0.958
Coal CH_4 emission factor (g CH_4/kg Coal)	0.0092
Coal N_2O emission factor (g N_2O/kg Coal)	0.014

Table 6.16: Brown coal properties and main combustion products for a nominal plant [12-14]. The coal is Latrobe Valley Brown Coal (from Appendix F2.2, p. 84, Draft GES [12]).

The calculation procedure for the brown coal case is similar to the black coal cases. The parameters are given in Table 6.17, and the specific cases in Table 6.18.

	Calculation stage	Variable / equation	Values, units & comments
1	Power delivered to grid	P	1000 MW_{el}
2	Load factor	λ	variable, 70% (60-80%)
3	Annual net electricity output	$E_{net} = P \times \lambda \times 8760$	$GWh_{el}\ y^{-1}$
4	Grid losses (total)	λ_d	variable, 5% (3%-9%)
5	Annual electricity sent-out	$E = E_{net} / (1 - \lambda_d)$	$GWh_{el}\ y^{-1}$
6	Sent-out efficiency	$\varepsilon_{so} = \varepsilon_g \times \varepsilon_b \times (1 - \chi_{aux})$	variable, calculated
7	Auxiliary load fraction	$\chi_{aux} = P_A / P_G$	5%, ratio auxiliary load to total generated
8	**Generator efficiency**	ε_g	**variable, 44% (42-45%)**
9	**Boiler efficiency**	ε_b	**variable, 70% (65-75%)**
10	Nominal power	$P_{nom} = P / \lambda / (1 - \lambda_d) (1 - \chi_{aux})$	MW_{el} , variable calculated
11	Lifetime	T	variable, 30 years (25-35)
12	Coal transport distance	X	2 km, assumed by rail
13	**Gross specific energy of coal**	Q_{gr}	**10.2 MJ/kg (data)**
14	Thermal energy required	$Q_{th} = E / \varepsilon_{so}$	$GWh_{th}\ y^{-1}$
15	Coal required	$M = Q_{th} / (Q_{gr} / 3.6) \times 1000 \times T$	tonnes
16	Coal emissions factor	EF	0.958 kg CO_2-e / kg coal, calc. from coal data, negligible CH_4 and N_20 emissions from combustion (Section 7.3, [15])
17	**Coal GHG emissions**	$GHG_{coal} = M \times EF$	tonnes CO_2-e, mainly CO_2 from combustion
18	Mining CH_4 emissions		Negligible
19	Mining (energy & GHG)	eg. $E_{mining} = M \times F_{mine}$	$GWh_{th/el}$ & tonnes CO_2-e, factors from Table 6.3 of EcoInvent report [16]
20	Transport (energy & GHG)	eg. $GHG_{trans} = M \times X \times EF_{trans}$	GWh_{th} & tonnes CO_2-e, rail data from Table 5.4, diesel fuel emission factor
21	Construction (energy & GHG)	*Eg.* E_{cons} = *inventory* × IO energy & GHG coefficients	$GWh_{th/el}$ & tonnes CO_2-e, various material inventories and in the worst case from Hill and Walford [1, 17]
22	Decommissioning	*Eg.* $E_{decom} = E_{cons} \times 0.05$	Assumed to be 5% of construction

Table 6.17: Calculation steps and main assumptions in the energy and emission calculations for new brown coal generation. Base case values are given and low to high ranges are shown in parentheses. The important contribution is shown in bold.

Main parameters	Base	High	Low
Load factor (%)	80%	70%	90%
Grid losses (%)	5%	9%	3%
Turbine efficiency (%)	44%	42%	45%
Boiler efficiency (%)	75%	70%	75%
Efficiency (sent-out %)	31.4%	27.9%	32.1%
Lifetime (years)	30	25	35
Coal emissions factor (kg CO_2-e / kg coal)	0.958	1.05	0.86

Table 6.18: Main analysis parameters for each case for brown coal generation. High parameters will raise the energy and greenhouse intensities.

The breakdown of results (Table 6.19) shows the expected dominance of direct combustion on the energy and emissions. Energy required for mining is, as explained above, probably a high estimate, although is less than the corresponding proportion found in an IO study by Friedrich and Marheineke [27]. All other contributions are very small.

Breakdown	Electricity	Thermal	Total energy		Total emissions	
	(GWh_{el})	(GWh_{th})	(GWh_{th})	(%)	(kt CO_2-e)	(%)
Mining	6,229	1,298	20,607	2.27%	6,677	2.16%
Transport	0	104	104	0.01%	29	0.01%
Construction	864	3,421	6,044	0.66%	1,958	0.63%
Combustion coal	0	882,397	882,397	97.02%	299,927	97.16%
Decommissioning	42	171	302	0.03%	98	0.03%

Table 6.19: Total full chain energy and emissions for the base case for brown coal.

Full energy and greenhouse intensity results are shown below. The base case greenhouse intensity of 1175 g CO_2-e/kWh is in agreement with the best practice values shown in Figure 6.2 and Table 6.2. Typically the emissions intensities of Victorian brown coal electricity range between 1200 to 1300 g CO_2-e/kWh, as calculated by the CCSD LCA method [5]. A sent-out efficiency of 31.4%, which the base case here assumes world's best practice and is comparable to the efficiency quoted for a supercritical brown coal plant in Table 6.5. Other references recommend, and indeed the Australian generation standards stipulate, that such an efficiency is however achievable with subcritical conditions. Most of the European brown coal plants included in the EcoInvent report have emissions intensities of between 1040 to 1400 g CO_2-e/kWh [16], in good agreement with the range calculated here.

Case	**Energy intensity**	**Greenhouse gas intensity**	**Lifetime output**	**Comment**
	(kWh_{th}/kWh_{el})	(g CO_2-e/kWh)	(GWh_{el})	
Base	3.46	1175	262,800	97% of emissions are from combustion
High	4.06	1506	219,000	97% of emissions are from combustion
Low	3.31	1011	306,600	97% of emissions are from combustion

Table 6.20: Summary of full chain energy and greenhouse intensities for brown coal electricity generation.

The spreadsheet tool ("Brown coal" worksheet) can be used to explore the parameters.

6.4 Natural gas fired electricity

In this section energy and emissions intensities for open and combined cycle natural gas generation are presented. Base case scenarios, together with high and low bounds are developed.

6.4.1 Fuel characteristics

Natural gas has a lower emissions coefficient per unit of energy than black and brown coal. Typical fuel properties assumed in this study are shown in Table 6.21. They are from the AGO's Workbook for stationary energy and apply for large users for whom distribution losses are small [18]. Direct emissions are mainly carbon dioxide from combustion. Indirect emissions are mainly methane leaks from the gas production and transmission system. They are similar to the figures of direct 51.6 kg CO_2-e / GJ and indirect 11.3 kg CO_2-e / G, assumed in CCSD reports, see Table 8 [25] and Table 6.4 [28].

Gas property	**Value**	**High**	**Low**
Direct emissions coefficient (kg CO_2-e / GJ)	52.0	52.6	51.7
Indirect emissions (kg CO_2-e / GJ)	16.0	18	10.0
Total emissions (kg CO_2-e / GJ)	68.0	70.6	61.7
Energy content (MJ/m^3)	39.5	41.0	38.0
Energy content (GJ/t)	52.0	53.9	50.0

Table 6.21: Natural gas properties and main emissions assumed [18]. This gas profile is similar to the generator standards reference case [12, 14]. Figures are considered Australian averages.

6.4.2 Conversion technologies

Typical characteristics of natural gas electricity generation capacity are shown in Table 6.22. A base case efficiency of 36% will be assumed for the open cycle system since the case here is assumed to be a large turbine (~200 MW_{el}) in line with best practice for large turbines (Table 6.5). This is similar to CCSD's case study of an 85 MW_{el} open cycle turbine, where a sent-out efficiency of 35.5% was used [28]. Note that smaller open cycle gas turbines are likely to have thermal efficiencies of up to 38% as indicated below.

Technology	Year	Net thermal efficiency (%)	Life cycle emissions intensity (g CO_2-e/kWh_{el})	Capital cost ($/$kW_{el}$)
Open cycle (NG)	2000, 2050	38.0	438 (347 direct)	340
Combined cycle (NGCC)	2002	53.2		825
Combined cycle (NGCC)	2010	56		670
Combined cycle (NGCC)	2030	65		614

Table 6.22: Performance characteristics of natural gas conversion. Capital costs are indicative only. Various sources are used: Tables 1 & 2 [25], and Tables 5.1, 5.3, 5.5 [23].

The performance of a combined cycle plant is also calculated, with a nominal turbine efficiency of 46%, which is below the target of the new generation efficiency standard of 52% [12] and world best practice (Table 6.23). There are only a few open cycle gas turbines which would achieve 35.5% in Australia at present, and perhaps no combined cycle plants achieving efficiencies as high as 52%. The main operational factors affecting the in-service efficiencies of gas turbines are the size of the unit, the ambient temperature, and the cooling method. Australian conditions are generally less favourable than typical European conditions for achieving combined cycle efficiencies as high as 53%. Auxiliary power requirements of 2% (net) are used for all cases, consistent with the fraction in Table 6.23. Construction requirements are calculated using the costs indicated in Table 6.22, along with similar factors as for the coal cases, and is very small in any case [28]. Transport energy use for the natural gas is deemed to be negligibly small.

Heat input (MW_{th})	Gas turbine output (MW_{el})	Steam turbine output (MW_{el})	Total power output (MW_{el})	Boiler auxiliaries (MW_{el})	Overall thermal efficiency (%)
732.8	250.2	145.7	395.9	5.9	53.2%

Table 6.23: Performance characteristics of current world best practice natural gas combine cycle systems, from Table 5.1 [23].

Main parameters are given below for the open cycle case (Table 6.24) and the combined cycle case (Table 6.25). Aside from the efficiency difference, the main difference in parameters for the two technologies are that a 20 % capacity factor (10-30%) is assumed for the open cycle plant, consistent with it operating as peaking capacity, at similar to current utilisation levels of gas plant (Table 6.2). The combined cycle natural gas plant is assumed to be base-load and operating at a capacity factor of 80% (70-90%).

Main parameters	**Base**	**High**	**Low**
Load factor (%)	20%	10%	30%
Grid losses (%)	5%	9%	3%
Turbine efficiency (%)	36%	34%	38%
Auxiliary electricity requirement (%)	2%	2%	2%
Efficiency (sent-out %)	35.3%	33.3%	37.2%
Lifetime (years)	30	25	35
Fuel factors	See Table 6.21		

Table 6.24: Main analysis parameters for open cycle natural gas generation. Other parameters are the same as for the coal cases. High parameters will raise the energy and greenhouse intensities.

Main parameters	**Base**	**High**	**Low**
Load factor (%)	80%	70%	90%
Grid losses (%)	5%	9%	3%
Turbine efficiency (%)	46%	44%	48%
Auxiliary electricity requirement (%)	2%	2%	2%
Efficiency (sent-out %)	45.1%	43.1%	47.0%
Lifetime (years)	30	25	35
Fuel factors	See Table 6.21		

Table 6.25: Main analysis parameters for combined cycle natural gas generation.

The breakdown of open cycle results (Table 6.26) shows the expected dominance of direct combustion on the energy and emissions. Indirect methane emissions from gas supply are however significant. All other contributions are very small.

Breakdown	Electricity	Thermal	Total energy		Total emissions	
	(GWh_{el})	(GWh_{th})	(GWh_{th})	(%)	(kt CO_2-e)	(%)
Methane indirect	0	0	0	0.00%	45,164	22.87%
Construction	2,272	9,184	16,226	2.03%	5,527	2.66%
Combustion gas	0	784,103	784,103	97.87%	146,784	74.33%
Decommissioning	114	459	811	0.1%	263	0.13%

Table 6.26: Total full chain results for the base case for open cycle NG generation.

The total greenhouse gas intensities for open cycle natural gas systems for the base case are 751 g CO_2-e/kWh (Table 6.27). This is significantly higher than the gas case study developed by CCSD which has 608 g CO_2-e/kWh [28]. The two main reasons for this difference are firstly that the CCSD study is for Western Australia which as lower indirect gas emissions (approximately 7 kg CO_2-e / GJ compared with the 16 kg CO_2-e / GJ assumed here in the base case), and secondly, because grid losses are not considered in that study. These authors also note (Page B6-8) that there is considerable uncertainty in the emissions from extraction of natural gas, varying from a minimum of 3.7 % up to 16.4%. Once again, the high and low ranges given below are very conservative bounds to the analysis. Finally, the results are consistent with the year 2000 European gas turbine average of 640 g CO_2-e/kWh (530 g CO_2-e/kWh direct) given the lower indirect emissions in the fuel chain (page 83 [29]).

Case	**Energy intensity** (kWh_{th}/kWh_{el})	**Greenhouse gas intensity** (g CO_2-e/kWh)	**Lifetime output** (GWh_{el})	**Comment**
Base	3.05	751	262,800	74% of emissions are from combustion
High	3.46	891	219,000	70% of emissions are from combustion
Low	2.81	627	306,600	82% of emissions are from combustion

Table 6.27: Summary of full chain intensities for open cycle gas turbine generation.

The breakdown of combined cycle results (Table 6.28) again shows the expected dominance of direct and indirect emissions associated with the fuel.

Breakdown	Electricity	Thermal	Total energy		Total emissions	
	(GWh_{el})	(GWh_{th})	(GWh_{th})	(%)	(kt CO_2-e)	(%)
Methane indirect	0	0	0	0.00%	35,346	23.3%
Construction	568	2,296	4,057	0.66%	1,314	0.87%
Combustion gas	0	613,646	613,646	97.30%	114,875	75.77%
Decommissioning	28	115	203	0.03%	66	0.04%

Table 6.28: Total full chain energy and emissions for the base case for combined cycle NG.

The total greenhouse gas intensity for combined cycle natural gas systems for the base case is 577 g CO_2-e/kWh (Table 6.29). This is significantly lower than the open cycle gas case which has 751 g CO_2-e/kWh, and is due purely to the higher conversion efficiency. The high and low ranges given below are very conservative bounds to the analysis. The base case is still not as low as the figure of 438 g CO_2-e/kWh given in Table 6.22 [23]) but that figure is reproducible if a higher conversion efficiency of 53% is included and grid losses are ignored.

Case	Energy intensity	Greenhouse gas intensity	Lifetime output	Comment
	(kWh_{th}/kWh_{el})	(g CO_2-e/kWh)	(GWh_{el})	
Base	2.35	577	262,800	76% of emissions are from combustion
High	2.57	655	219,000	74% of emissions are from combustion
Low	2.20	491	306,600	83% of emissions are from combustion

Table 6.29: Summary of full chain intensities for combined cycle gas turbine generation.

The low case results here are roughly consistent with the world's best combined cycle gas turbine (in Germany with a net efficiency of about 58%) leading to an emissions intensity of 420 g CO_2-e/kWh (page 83 [29]), again with lower indirect fuel emissions.

The spreadsheet tool ("Natural gas" worksheet) can be used to explore the parameters. The index in Row 21 allows efficiencies for open vs. combined cycles to be selected. Similarly the index in Row 20 allows cycling through the base, high and low properties of the fuel cycles. Other parameters are changed manually (excluding greyed-out cells).

6.5 Wind power

Wind turbines use a century-old technology, previously used to pump water, but now fast becoming an increasingly important part of global power supplies. Electricity generation from wind comes from the conversion of the kinetic energy in the air to mechanical energy in the turbine. This mechanical energy is used to drive a generator to create electricity.

6.6.1 Australian industry sector

Australia has "one of the strongest and most abundant wind resources on the planet" [30], but currently has less than 1% of its annual electricity requirements supplied by wind power. At present, the Australian wind industry sector has a capacity of about 739 MW_{el} [31], producing about 1560 GWh per year implying an average capacity factor of about 24%. Most of this capacity is in South Australia, followed by Victoria and Western Australia (Figure 6.3). These states have the highest and most consistent wind speeds, whilst NSW has more moderate winds. The importance of consistent high wind speeds is due to cubic increases in the quantity of power derived from increases in wind speeds (eg. a doubling of wind speed results in eight times the power produced).

The Australian Wind Energy Association (AusWEA) see a potential of 6% of Australia's total electricity requirement being supplied by wind energy by 2010, but this is subject to further integration of the national grid [32]. A study by Hugh Outhred for the AGO has estimated that over the next decade, if new capacity is widely and evenly dispersed over the national grid, there is potential for 8000 MW_{el} of wind energy to be 'readily accepted' into the National Electricity Market (NEM) [33]. A capacity of 8000 MW_{el} by 2016, would be supplying roughly 10% of Australia's electricity requirement. The incorporation of this extra capacity, however, would need better regional planning of wind power sites, better wind forecasting and better integration of the sites with the national grid [33].

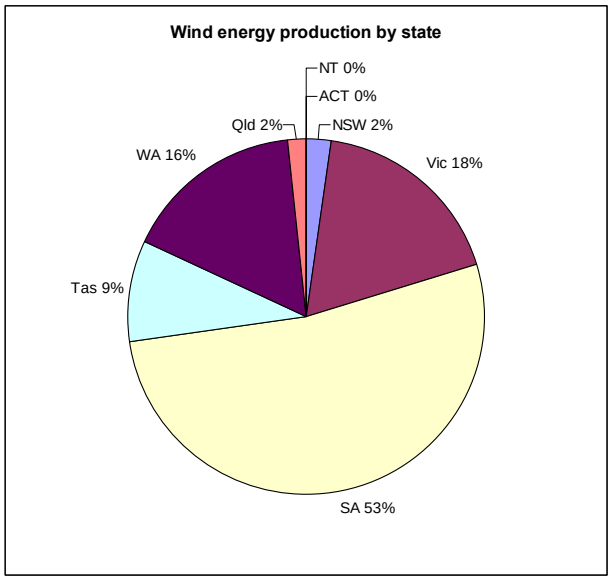

Figure 6.3: Wind energy production by state [31, 34].

Wind power is limited somewhat in its potential capacity in the Australian NEM due to its intermittent nature. Whilst wind power can be an important and low cost source of renewable energy, its unreliability necessitates back-up capacity for the times when wind speeds are too low (and in rare cases too high). The importance of this issue is alleviated by distributing capacity over a wide geographical area, such that regional variations are smoothed out. Improvements in forecasting will also allow more time for grid controllers to bring non-immediate forms of capacity (e.g. coal power) online if required and balance supply and demand changes using pumped hydro and perhaps other energy storage in the longer term.

The AGO maintains a database on renewable energy projects in Australia [31]. Established wind projects are listed in Table 6.30. There is a trend towards larger turbines (typically 2 MW_{el} turbines) and groups of 20-40 turbines, with total farm capacities being less than about 100 MW_{el}. All operating wind farms are onshore in Australia, though there is increasing international interest in offshore farms with single turbines up to 4.5 MW_{el} in size.

The Centre for Energy and Environmental Markets and Energy Systems Research Group both at the UNSW have investigated various structural issues, including the employment benefits of wind power [35], the requirements for integrating wind energy into the national grid [also, 32, 36] [37, 38], and the potential for readily accepted wind energy in the National Electricity Market [39, 40]. Limits of around 10% of grid capacity for wind power in the near future were found in these studies, mainly due to the high variability of wind.

6.6.2 Existing LCA studies

Significant work has been carried out on analysing the life cycle of wind turbines, in terms of cost intensities, energy intensities and/or greenhouse intensities. In order to condense the main findings of this large volume of literature into this report, an overview is presented in Table 6.31. Studies are listed in order of increasing power rating. There is a broad range of studies, sizes, capacity factors and other parameters. Studies also vary over the extent to which they address the full energy and emissions chain. Some studies also include the energy and emissions consequences of cost of grid connection to wind farms. The trend to larger turbines is again apparent and with generally decreasing energy and CO_2 intensities. Although there are outlining figures the averages of such a large number of studies are still meaningful. The average energy intensity is 0.11 kWh_{th}/kWh_{el} and the average greenhouse intensity is 27 g CO_2-kWh_{el}.

Name or Location	State	Owner/Developer	Year	Total capacity (MW_{el})	No. of turbines	Type	Turbine size (kW_{el})
Breamlea	VIC	Barwon Water	1987	0.06	1	Westwind	60
Flinders Island 1	TAS	Hydro Tasmania	1988	0.055	1	na	55
Cooper Pedy	SA	Na	1991	0.15	1	Nordex	150
Ten Mile Lagoon	WA	Western Power	1992	2.025	9	Vestas	225
Aurora (Brunswick)	VIC	Citipower	1993	0.01	1	na	10
Flinders Island 2	TAS	Hydro Tasmania	1996	0.025	1	na	25
Armadale	WA	Na	1997	0.03	1	Westwind	30
Thursday Island	QLD	Ergon Energy	1997	0.45	2	Vestas	225
Kooragang Island, Newcastle	NSW	Energy Australia	1997	0.6	1	Vestas	600
Huxley Hill, King Island	TAS	Hydro Tasmania	1998	0.75	3	Nordex	250
Crookwell	NSW	Eraring Energy	1998	4.8	8	Vestas	600
Denham	WA	Western Power	1999	0.69	3	Enercon	230
Epenarra	NT	na	1999	0.08	1	Lagerway	80
Murdoch	WA	ACRE	2000	0.02	1	Westwind	20
Windy Hill	QLD	Stanwell	2000	12	20	Enercon	600
Blayney	NSW	Eraring Energy	2000	9.9	15	Vestas	660
Albany	WA	Western Power	2001	21.6	12	Enercon	1800
Codrington	VIC	Pacific Hydro	2001	18.2	14	Bonus	1300
Hampton	NSW	Wind Corporation Australia	2001	1.32	2	Vestas	660
Woolnorth Stage 1	TAS	Hydro Tasmania	2002	10.5	6	Vestas	1750
Toora	VIC	Stanwell	2002	21	12	Vestas	1750
Exmouth Advanced	WA	Western Power	2002	0.06	3	Westwind	20
9 Mile Beach	WA	Western Power	2003	3.6	6	Enercon	600
Huxley Hill stage 3	TAS	Hydro Tasmania	2003	1.7	2	Vestas	850
Starfish Hill	SA	Tarong Energy	2003	34.5	23	NEG Micon	1500
Mawson Base	AAT	Australian Antartic Division	2003	0.6	2	Enercon	300
Challicum Hills	VIC	Pacific Hydro	2003	52.5	35	NEG Micon	1500
Hopetoun	WA	Western Power	2004	0.6	1	Enercon	600
Rottnest Island	WA	Rottnest Island Board	2004	0.6	1	Enercon	600
Lake Bonney Stage 1	SA	Babcock & Brown National Power	2004	80.5	46	Vestas	1750
Bluff Point (Woolnorth Stage 2)	TAS	Hydro Tasmania	2004	54.25	31	Vestas	1750
Canunda	SA	International Power/ Wind Prospect	2004	46	23	Vestas	2000
Bremer Bay	WA	Western Power	2005	0.6	1	Enercon	600
Cocos (Keeling) Island	WA	PowerCorp/Diesel & Wind Systems	2005	0.08	4	Westwind	20
Walkaway	WA	B&B/National Power/Carbon Solutions	2005	89.1	54	Vestas V82	1650
Wonthaggi	VIC	Wind Power Pty Ltd	2005	12	6	REpower	2000
Cathedral Rocks	SA	Hydro Tasmania & Acciona	2005	66	33	na	2000
Mount Millar (Yabmana)	SA	Tarong Energy	2005	70	35	Enercon	2000
Wattle Point	SA	Southern Hydro & Wind Farm	2005	90.75	55	Vestas	1650
Yambuck	Vic	Pacific Hydro	2006	30	20	NEG Micon	1500
Total	**Aus**			**737.7**	**496**		

Table 6.30: Currently operating wind farms in Australia (May, 2006) [31, 34].

Refe-rence	Year of study	Location	Energy Intensity $\left(\frac{kWh_{in}}{kWh_{el}}\right)$	CO_2 intensity $\left(\frac{g\,CO_2}{kWh_{el}}\right)$	Power rating (kW_{el})	Life time (y)	Load factor (%)	Ana-lysis type	Scope as stated	Turbine type	$\varnothing_r$ (m)	H (m)	Rated wind speed (m/s)	Remarks
[41]	1992	Germany[o]	0.089		0.3	20	38.8	PA	CDMOT	3-bl	1.5	11.6	9.0	75% recycling
[42]	1983	Germany[o]	≈0.43		2	15	45.7	AEI	CM					Average values
[43]	1998	Argentina[c]	≈0.17	≈42	2.5	20	22.0	PA	CMT(O)	2/3-bl				Incl. Storage
[44]	1981	USA[o]	1.016		3	20	26.8	I/O	CMO		4.3	20	10.1	Excl. storage
[42]	1983	Germany[o]	≈0.29		6	15	45.7	AEI	CM					Average values
[42]	1983	Germany[o]	≈0.20		12.5	15	45.7	AEI	CM					Average values
[45]	1997	Denmark[o]	0.120		15	20	20.5	I/O	CMO	1980	10	18		Vintage model
[45]	1997	Denmark[o]	0.123		22	20	19.9	I/O	CMO	1980	10.5	18		Vintage model
[46]	1991	Germany[o]	0.085		30	20	14.4	PA	CGMOT	2-bl	12.5	14.8	13	Hsw-30
[47]	1996	Switzerland[o]	0.321	52	30	20	7.9	PA	CDGMOT	2-bl	12.5	22	11.4	Simplon
[45]	1997	Denmark[o]	0.100		30	20	19.0	I/O	CMO	1980	11	19		Vintage model
[43]	1998	Argentina[c]	0.120	≈29	30	20	22.0	PA	CMT(O)	2/3-bl				
[42]	1983	Germany[o]	≈0.12		32.5	15	45.7	AEI	CM					Average values
[46]	1991	Germany[o]	0.049		33	20	29.4	PA	M	2-bl	14.8	22	11	MAN-Aeromann
[48]	1991	Germany	0.053		45	20	33.5	PA	M		12.5			
[45]	1997	Denmark[o]	0.066		55	20	20.6	I/O	CMO	1980	16	20		Vintage model
[49]	1990	Denmark[o]	0.014		95	20	25.2	PA	M(C)	3-bl	19	22.6		On-shore farm (6)
[46]	1991	Germany[o]	0.068		95	20	20.5	PA	CGMT	3-bl	19	22.6		On-shore farm (6)
[46]	1991	Germany[o]	0.051		95	20	20.5	PA	M	3-bl	19	22.6		Tellus 95
[50]	1991	Japan[o]	0.252	71.7[e]	100	20	31.5	I/O	CMT					
[46]	1991	Germany[o]	0.060		100	20	20.9	PA	M	2-bl	34	24.2	8	Hütter 100
[20]	1992	Japan[o]	0.345	95.6[e]	100	20	31.5	I/O	CMOT					10% auxiliary power
[51]	1992	Japan[o]	0.033	33.7	100	30	28.0	I/O	CMOT		30		13	Upwind propeller
[51]	1992	Japan[o]	0.054		100	30	40.0	I/O	CMOT	1983	30		10	Downwind propeller
[52]	1996	Germany[o]	0.120	17	100	20	31.4	PA	CMO	3-bl	20	30		
[53]	1996	Japan[o]	0.436	123.6[e]	100	30	20.0	I/O	CMO					Downwind propeller
[54]	1996	Japan[o]	0.456	123.7[e]	100	20	18.0	I/O	CMO	1984	30			Demonstration plant
[55]	2001	Japan[o]	0.160	39.4	100	25	34.8	I/O	CMT		30	30		NO_x & SO_x calculated
[56]	1990	Denmark[o]	0.021	8.81	150	25	30.1	PA	M					
[46]	1991	Germany[o]	0.049		150	20	25.6	PA	M	3-bl	23	30	13	AN-Bonus 150

[47]	1996	Switzerland[o]	0.202	28	150	20	7.6	PA	CDGMOT	3-bl	23.8	30		Grenchenberg
[46]	1991	Germany[o]	0.037		165	20	23.2	PA	M	3-bl	25	32	13.5	Adler 25
[54]	1996	Japan[o]	0.171	47.4[e]	170	20	22.5	I/O	CMO		27			Mitsubishi-2
[46]	1991	Germany[o]	0.053		200	20	21.0	PA	M	3-bl	26	30	13	Adler 26
[48]	1991	Germany	0.031		225	20	39.9	PA	M		27			
[43]	1998	Argentina[c]	≈0.08	≈18	225	20	22.0	PA	CMT(O)	2/3-bl				
[46]	1991	Germany[o]	0.064		265	20	19.0	PA	M	2-bl	52	30.5	8.5	Voith 52/265.8
[57]	1990	Germany[o]	0.031		300	20	28.9	PA	CMT	3-bl	32	34	11.5	Enercon-32
[58]	2005	Japan		29.5	300	30	20	PA	CO					System not specified
[48]	1991	Germany	0.037		300	20	39.9	PA	M		32			
[41]	1992	Germany[c]	0.027		300	20	41.9	PA	CDGMOT	3-bl	32	34		75% recycling
[59]	1993	Germany[o]	0.046	11[e]	300	20	22.8	PA	CDMOT					Recycling
[60]	1994	Germany[o]	0.022		300	20	22.8	PA	MO(D)					O calculated with AEI
[54]	1996	Japan[o]	0.118	34.9[e]	300	20	18.0	I/O	CMO		28			Mitsubishi-1
[61]	1995	UK[o]	0.042	9.1	350	20	30.0	PA	M	3-bl	30	30	≈15	
[58]	2005	Japan		20.3	400	30	20	PA	CO					System not specified
[54]	1996	Japan[o]	0.088	24.1[e]	400	20	18.0	I/O	CMO		31			MICON
[62]	1997	Denmark[o]	0.020	15.9	400	20	22.8	PA	M(O)					Excl. imports
[46]	1991	Germany[o]	0.048		450	20	20.0	PA	GM	3-bl	35	36	18	AN-Bonus 450
[27]	1994	Germany[o]		18.2[e]	500	20	27.4	I/O	CM					Incl. factory buildings
[63]	1994	Germany[o]	0.068	8.1	500	20	36.5	PA	M	2/3-bl	39	41		
[64]	1998	Germany[o]	0.042		500	20	29.6	PA	CGMOT	3-bl	40.3	44		Enercon E-40
[64]	1998	Germany[o]	0.065		500	20	29.6	I/O	CGMOT	3-bl	40.3	44		Enercon E-40
[65]	2001	Brazil[o]	0.069		500	20	29.6	I/O	CGMOT	3-bl	40.3	44		E-40;Transp.D→Brazil
[66]	2000	Denmark[o]	0.033	9.7	500	20	25.1	PA	M(DT)	3-bl		41.5		On-shore farm (18)
[66]	2000	Denmark[o]	0.047	16.5	500	20	28.5	PA	GM(DT)	3-bl	39	40.5	16	Off-shore farm (10)
[45]	1997	Denmark[o]	0.037		600	20	26.5	I/O	BCDEGMOT	3-bl	47	≈50	15	
[67]	2000	Belgium[o]	0.033	9.2[e]	600	20	34.2	PA	DM(O)					
[67]	2000	Belgium[o]	0.036	7.9[e]	600	20	34.2	I/O	DM(O)					1980 I/O tables
[68]	2004	Switzerland			600	20	14	PA		Nordex	43	40		
[69]	2001	Australia	0.04	12.2	600	30	21	PA	CMT	3-bl	45	48		Vestas V44 600 kW
[68]	2004	Europe		11	800	20	17	PA		Nordex	50	50		Onshore
[70]	1980	UK[c]	0.080		1000	25	18.3	I/O	CM		46		18.4	On-shore farm (5)
[70]	1980	UK[c]	0.165		1000	25	18.3	I/O	CM		46		18.4	
[71]	1996	Germany[o]		14[e]	1000	20	18.5	PA	CMO	3-bl	54	55		HSW 1000
[71]	1996	Germany[o]		22[e]	1000	20	18.5	I/O	CMO	3-bl	54	55		HSW 1000
[52]	1996	Germany[c]	0.035	10	1000	20	36.2	PA	CMO	3-bl	60	50		
[72]	1977	USA[c]	0.023		1500	30	50.4	I/O	BCEMT	2-bl	≈60	≈50	10.5	Steel truss tower

[45]	1997	Denmark[c]	0.030		1500	20	38.4	I/O	CMO	3-bl	64	55	17	Off-shore
[73]	2006	Germany	0.03	11	1500	25	-	PA	CMT					Dynamic changes
[64]	1998	Germany[o]	0.046		1500	20	31.0	PA	CGMOT	3-bl	66	67		⎫ Enercon
[64]	1998	Germany[o]	0.071		1500	20	31.0	I/O	CGMOT	3-bl	66	67		⎬ E-66;
[74]	1999	Germany[c]	0.038		1500	20	31.0	PA	CDGMOT		66	67		⎭ no gear box
[74]	1999	India[c]	0.032		1500	20	45.9	PA	CDGMOT		66	67		E-66;Transp.D→India
[68]	2005	Baltic Sea		13	2000	20	30	PA		Bonus	76	60		Offshore
[75]	2004	Denmark	0.02	7.62	2000	20	46	PA	CDMOT	3-bl		78		Vestas V80 Offshore
[75]	2004	Denmark	0.02	6.83	2000	20	32	PA	CDMOT	3-bl		60		Vestas V80 Onshore
[73]	2006	Germany	0.03	8.9	2500	25	-	PA	CMT					Dynamic changes
[42]	1983	Germany[o]	≈0.79		3000	20	45.7	AEI	CM	2-bl	100	100		GROWIAN prototype
[46]	1991	Germany[o]	0.065		3000	20	30.4	PA	GM	2-bl	100	100	12	GROWIAN I
[48]	1991	Germany	0.045		3000	20	34.2	PA	M		80			
[76]	2005	Denmark	0.03	4.64	3000	20	16	PA	CDGMOT	3-bl		80		Vestas V90 Onshore
[76]	2005	Denmark	0.03	5.25	3000	20	31	PA	CDGMOT	3-bl		105		Vestas V90 Offshore
[77]	1996	UK[o]		≈25	6600	20	29	I/O	CDMO					System not specified
[78]	2002	Egypt		18.02	11250	25	-	PA	CO					System not specified
		Averages	**0.11**	**27**										

Notes: $\varnothing_r$=rotor diameter, AEI=Method of multiplying total cost with a national average energy intensity, [c]=conceptual, bl=blades, B=Business management, C=Construction, D=Decommissioning, [e]=CO_2 equivalents including CH_4 and N_2O, E=Engineering, G=Grid connection, *h*=Tower height, I/O=Input-output-based hybrid analysis, M=Manufacture, [o]=operating, O=Operation, PA=Process analysis, T=Transport, ()=partly covered.

Table 6.31: Overview of energy and CO_2 analyses of wind turbines.

6.6.3 Scenario description for wind power

The output of a wind turbine is highly site specific, and also quite dependent on the turbine size and properties. In order to define a realistic scenario, the cases here are based on the Challicum Hills wind farm established by Pacific Hydro in Victoria in 2003. This wind farm is approximately 53 MW_{el} in total capacity comprising 35 turbines each nominally 1.5 MW_{el}[2]. The farm is expected to have a capacity factor of about 31%, therefore producing 140 GWh per year. In order to model realistic outputs as a function of wind speed, the Danish Wind Industry Association's detailed online calculator is used [3] along with typical parameters. The details of the wind output calculations for the base case of 6 m/s average wind speed are given in Table 6.32. The calculator gives yearly outputs due to standard statistical fluctuations in the wind resource at the hub height. Specific parameters can be used for Australian sites, but the ones used here are sufficiently general.

Parameter	Unit	Value
Mean wind speed (@ 25 m)	m/s	6
Weibull shape parameter		1.5
Weibull scale parameter		6.65
Roughness length	M	0.055
Mean wind speed (@ hub)	m/s	6.9
Turbine rating	kW_{el}	1500
Hub height	M	62
Rotor diameter	M	72
Cut in wind speed	m/s	3
Cut out wind speed	m/s	25
Generation	GWh/y	4.1
Capacity factor		31.2%

Table 6.32: Base case output scenario for a nominal 1.5 MW_{el} wind turbine, based on the Challicum Hills wind farming using NEG Micon 1500/72 turbines and 6 m/s wind speed at 25 m height.

The major processes required for the installation and operation of a wind farm are outlined in Figure 6.4. A typical breakdown of major material inputs into a turbine is compiled in Table 6.33 from recent literature sources (listed below). The most process in development of a wind farm is the turbine construction (60-85% of cost [79-81], consisting of the rotor, nacelle and tower. Although these components are often constructed separately, standard technology is used, and requirements reported in the literature and industry are by turbine.

The major sources of literature combined to give an indication of material requirements were:

- Schleisner, L. (2000). "Life cycle assessment of a wind farm and related externalities." Renewable Energy 20(3): 279-288. [66]
- Voorspools, K. R., Brouwers, E. A. and D'haeseleer, W. D. (2000). "Energy content and indirect greenhouse gas emissions embedded in 'emission-free' plants: results from the Low Countries." Applied Energy 67: 307-330. [67]

[2] http://www.pacifichydro.com.au/docs/ChallicumHills.pdf
[3] http://www.windpower.org/en/tour/wres/pow/index.htm

- Keemoku, Y., Ishikawa, K., Nakagawa, S., Kawamoto, T. and Sakakibara, T. (2002). "Life Cycle CO2 Emissions of a Photovoltaic/Wind/Diesel Generating System." Electrical Engineering in Japan 138(2): 14-23. [82]
- Elsam Engineering (2004). Life Cycle Assessment of offshore and onshore sited wind farms. Denmark, Vestas Wind Systems: 54. [75]
- Vestas (2005). Life cycle assessment of offshore and onshore sited wind power plants based on Vestas V90-3.0 MW turbines. Denmark, Vestas Pty Ltd: 59. [76]
- Coal in a Sustainable Society, 2001, Case study B13: Electricity from wind turbines, Revision 2.30. [69]

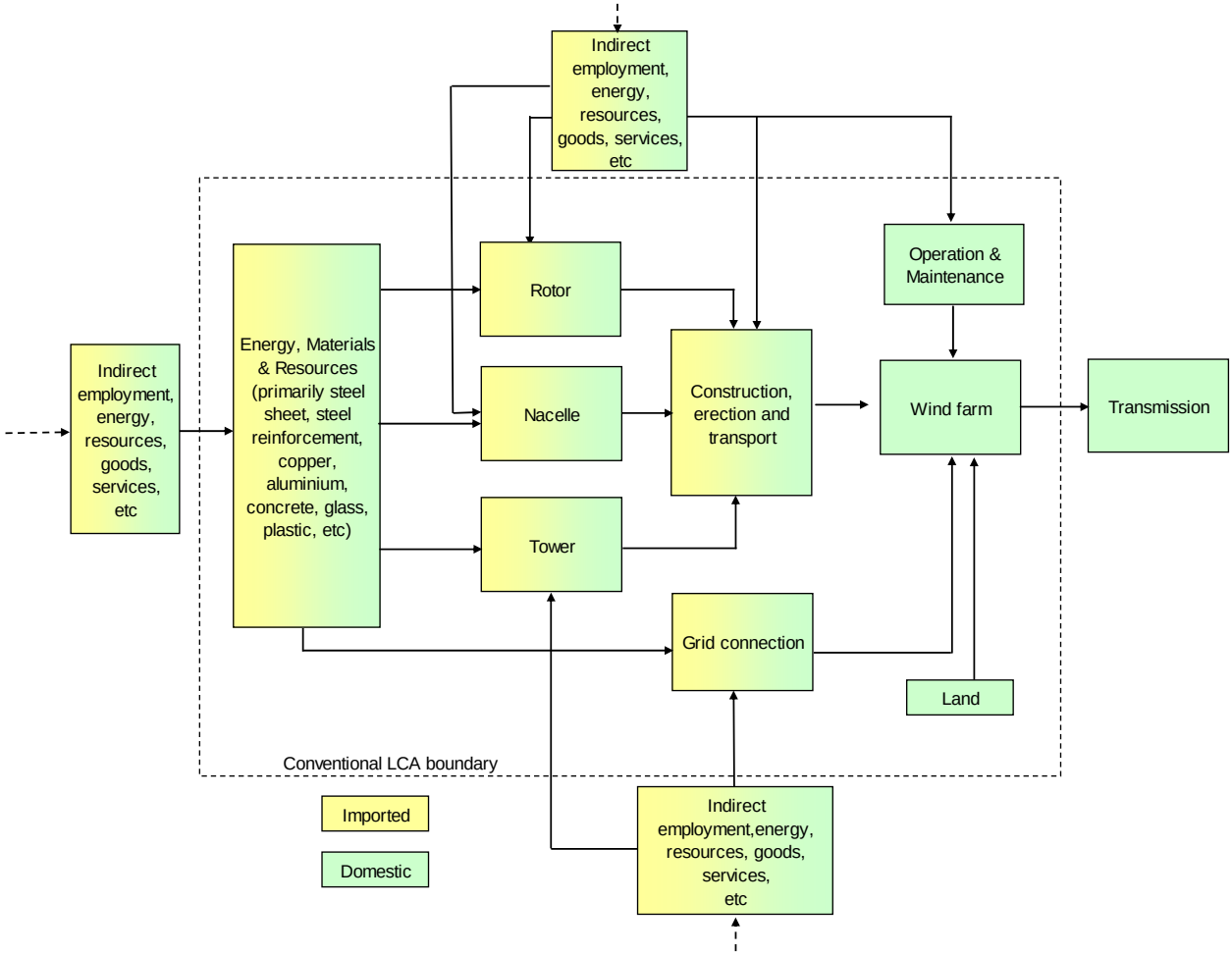

Figure 6.4: Major processes required for wind farm development and operation.

The material inventory is combined with input-output derived energy intensities, with an assumption of 10% electricity component to yield total energy requirements in terms of thermal energy and electricity per MW_{el} turbine rating, using a similar method to those for the other technology assessments in this report. Transport energy (and greenhouse) contributions are calculated by assuming a transport distance and the articulated truck transport details given in Table 3.17. International transport by ship of imported parts is a small contribution and is ignored. Construction energy requirements, as opposed to material requirements, are estimated conservatively as 3% of material requirements, further split into electricity at 25% and thermal energy at 75%, based on EcoInvent data (page 156 [16]), and consistent with Vattenfall's estimates (page 12 [83]).

In terms of operation direct greenhouse emissions for the turbine operation are zero, but other studies suggest that electricity is required when the turbines are not producing power. This is estimated as approximately 0.0075 kWh_{el} / kWh generated [83]. This is in reasonable agreement with the operational emissions figure of 8 g CO_2-e / kWh for a Japanese case [58]. In additional there are, emissions released from service vehicles, but these are negligible small and most wind farms require very little maintenance.

Material	Reference	Tonnes/MW	Average tonnes/MW
Concrete	Voorspools et al. 2000 [67]	360	**433**
	CCSD [69]	456	
	Vestas 2005 [76]	380	
	Schleisner 2000 [66]	565	
	Elsam Engineering 2004 [75]	403	
Steel	Voorspools et al. 2000 [67]	125	**116**
	CCSD [69]	93	
	Keemoku et al. 2002 [82]	126	
	Schleisner 2000 [66]	105	
	Elsam Engineering 2004 [75]	129	
Copper	Voorspools et al. 2000 [67]	4.4	**2.4**
	CCSD [69]	3.0	
	Schleisner 2000 [66]	0.7	
	Elsam Engineering 2004 [75]	1.4	
Aluminium	Voorspools et al. 2000 [67]	0.4	**1.4**
	CCSD [69]	1.5	
	Schleisner 2000 [66]	2.8	
	Elsam Engineering 2004 [75]	0.8	
Plastic	Voorspools et al. 2000 [67]	9.7	**8**
	CCSD [69]	12.0	
	Keemoku et al. 2002 [82]	14.0	
	Schleisner 2000 [66]	4.0	
	Elsam Engineering 2004 [75]	1.5	
Glass fibre	Elsam Engineering 2004 [75]	10.8	**6**
	Schleisner 2000 [66]	2.2	

Table 6.33: Major material inputs per MW for wind turbines with sources noted and averages used in bold.

Note that as with the other technology assessments, grid connection costs and related energy and emissions are not considered. The remoteness of many wind farms does often mean that new grid connections are required and studies often calculate the greenhouse requirements of these connections.

The foregoing sources and assumptions are used to develop base, high and low cases for a nominal rated 1.5 MW_{el} wind turbine (Table 6.34). The material intensity factor increases and

reduces the embodied energy (and emissions) in the material inventory by 20%. The base case here can be considered current state of the art equipment installed at good, but not extreme, site.

Main parameters	**Base**	**High**	**Low**
Grid losses (%)	5%	9%	3%
Wind speed (m/s)	6	5	7
Electricity out (GWh/year)	4.10	3.03	5.03
Capacity factor (%)	31.2%	23.1%	38.1%
Lifetime (years)	25	20	30
Transport distance (km)	250	400	150
Material intensity factor	1	1.2	0.8

Table 6.34: Main parameters for the wind power cases (turbine rating 1.5 MW_{el}). The high case corresponds to all parameters leading to high greenhouse intensities.

6.6.4 Energy and emissions intensities

The breakdown of wind power results for 150 MW_{el} rated wind farm based on the turbines described is given below (Table 6.35). Energy use and greenhouse emissions embodied in materials and to a lesser extent from operation are clear.

Breakdown	Electricity	Thermal	Total energy		Total emissions	
	(GWh_{el})	(GWh_{th})	(GWh_{th})	(%)	(kt CO_2-e)	(%)
Materials	37.1	333.7	371	66.6%	145	69.7%
Transport	0.0	10.0	10.0	1.8%	4.14	2.0%
Construction	2.8	8.3	11.1	2.0%	5	2.6%
Operation	53	0	165	29.6%	53	25.7%

Table 6.35: Total full chain results for the base case for a wind farm of 150 MW_{el} rating.

The total greenhouse gas intensity for the wind power base case is 21 g CO_2-e/kWh (Table 6.36) with a range of the high and low cases between 13 and 40 g CO_2-e/kWh, which are based on very conservative bounds to the analysis. These results are consistent with those given in Table 6.31 and its average of 27 g CO_2-e/kW, which can be explained mainly influence by the low capacity factor from the lower wind speed.

Case	**Energy intensity** (kWh_{th}/kWh_{el})	**Greenhouse gas intensity** (g CO_2-e/kWh)	**Lifetime output** (GWh_{el})	**Comment**
Base	0.066	21	9,378	31.2% capacity factor, 25 year lifetime
High	0.012	40	5,515	23.1% capacity factor, 20 year lifetime
Low	0.041	13	14,637	38.3% capacity factor, 30 year lifetime

Table 6.36: Summary of full chain intensities for 150 MW_{el} nominal wind farm.

The results above are in agreement with other studies with figures (in g CO_2-e / kWh) of 29.5 (small turbine) [58], 15-20 (typical) [84], 10-13 (smaller study boundary) [85], 11 (1.5 MW_{el} turbines onshore) [73], 28 (150 kW_{el} turbine Switzerland) [86], and ~25 (up to 1.5 MW_{el} turbines) [67]. The present results are higher than that given in the CCSD case study of Crookwell wind farm in NSW (capacity factor of 21%, 660 kWel turbines) of 12 g CO_2-e / kWh [69], despite the lower output and older technology assumed in this study. The figure for European conditions and electricity supply is ~10 g CO_2-e / kWh in the EcoInvent report [16]. These lower figures can be generally explained by different analysis boundaries and different electricity supply mixes and corresponding emissions intensities.

6.6 Photovoltaic electricity

Photovoltaic (PV) devices rely on direct solar radiation photons to cause a separation of charges in a suitable semiconductor material (the “photoelectric effect”), and with an electric circuit, to produce an electric current. The advantages of PV devices are that they are a very low maintenance, reliable, and modular source of direct renewable energy that require few ongoing inputs apart from sunshine, and once in operation, do not pollute.

6.6.1 Australian PV industry sector

At the start of 2005, the total installed photovoltaic capacity in Australia was estimated to be 52.3 MW_{el}, growing at around 15% per annum [87]. This represents about 2% of global installed PV capacity. Off-grid non domestic applications (including telecommunications, water pumping, signalling) are the dominant source of PV power in Australia with 57% of the installed capacity, followed by off-grid domestic at 30%. Only 13% of PV capacity in Australia is grid connected, of which only 3% is in centralised power generating facilities. The potential for the industry is large, with the Australian Business Council for Sustainable Energy estimating that 350 MW_{el} of capacity could be installed by 2010.

Increasing oil prices, and reducing PV prices, backed by government support (mainly through the Renewable Remote Power Generation Program - RRPGP) are behind growth in the off-grid domestic capacity share, whilst a range of government incentives including the Mandatory Renewable Energy Target and the national PV Rebate Program have seen growth in the grid-connected supply. Other newer incentives include the Solar Cities program and the Renewable Energy Development Initiative.

The distribution of PV installations across Australia shows a significant dominance by NSW, with 51% of installed capacity. The Northern Territory, with 20% of the Australian installed capacity shows the importance of PV in providing power for remote localities. The distribution is shown in Figure 6.6. These figures relate to the Australian Greenhouse Office renewable energy register [31] which does not reported installations of less than 3 kW_{el}.

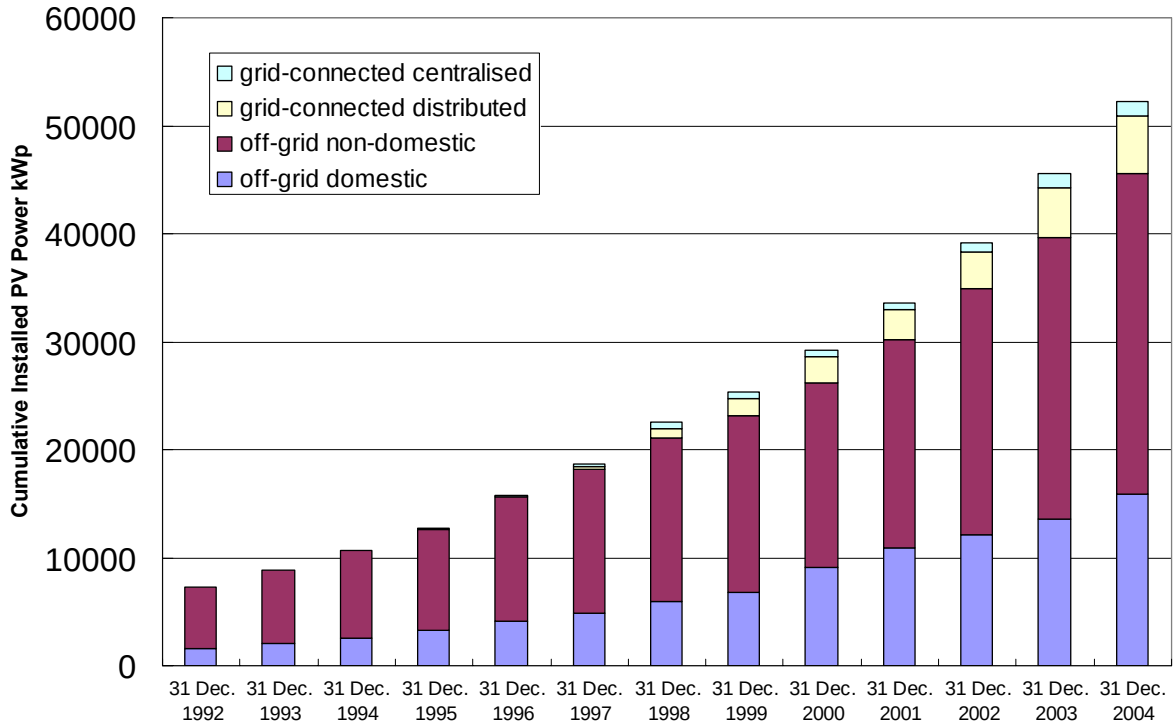

Figure 6.5: Cumulative installed PV power in Australia (kWp means peak output) [87].

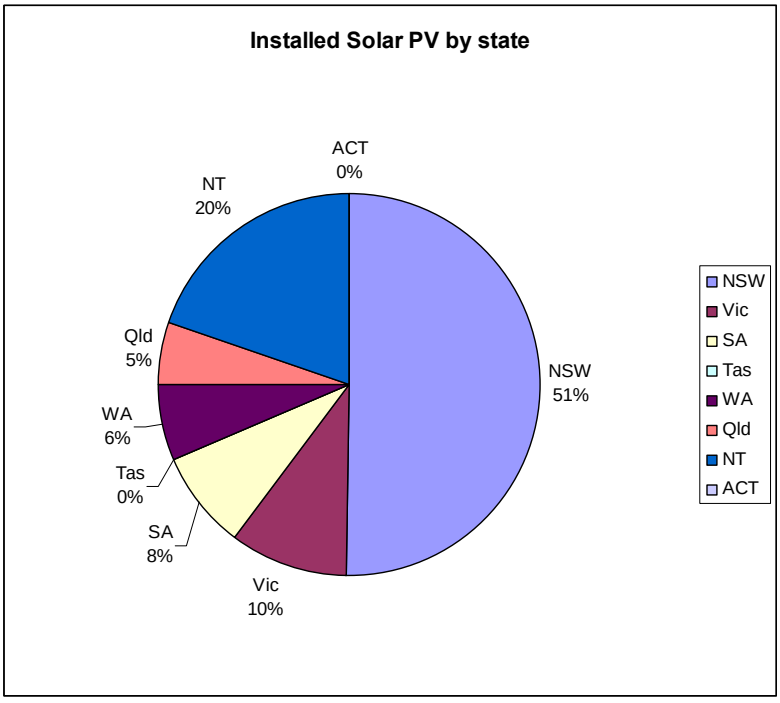

Figure 6.6: PV installed capacity by state (AGO data).

The PV manufacturing industry in Australia is growing, with 40 MW_{el} of capacity produced in 2004 and 50 MW_{el} produced in 2005. The BP Solar plant in Sydney is the largest producer. Most Australian production is exported, with 77% of cells, and 50% of modules exported, whilst of the module installed in Australia, 40% were imported [88]. The Origin Energy

commercialisation of the ANU's Sliver Cell technology came online with a 5 MW pilot line in 2005, but is still in the pre-commercial production stage. Currently, apart from non-crystalline dye sensitised cells, no crystalline wafers or feedstock is produced in Australia.

Reflecting rising international market prices, mainly due to competitive demand for silicon supply, module costs have risen to the AUD\$10/W_{peak} range [88], from AUD\$7/W_{peak} in 2002 and 2003 [89]. PV inverters and controllers are produced in Australia, with prices in the AUD\$1.3-1.9/W_{peak} for inverters up to 2.5kW and AUD\$0.4-1.0/W_{peak} for larger inverters. Supporting structures can be manufactured specifically for PV modules, and there are a range of Australian based options available.

The total system prices for 2003 in Australia provided by the International Energy Agency [89] are reproduced below. There is quite a range of costs, depending on the technology, application and scale of installations.

Category/Size	Typical applications and brief details	Current price per W_{peak} in AU\$
Off-grid Up to 1 kW_p	Residential, water pumping, telemetry, electric fences, lighting	18-24
Off-grid > 1 kW_p	Community power stations, diesel grid, pastoral stations, roadhouses, telecommunications, cathodic protection	12-18
Grid-connected	1-3 kW roof-mounted systems for households and schools	8-12
Grid-connected up to 10 kW_p	Community, industrial and commercial buildings	7-10
Grid-connected > 10 kW_p	Community, industrial and commercial buildings	6-10

Table 6.37: Turnkey prices for PV systems in Australia in 2003 [89].

6.6.2 Existing LCA studies

There has been a significant amount of energy and greenhouse analysis of photovoltaic devices over the last 20 years, with most concerning the energy ratio or energy pay back time and the life-cycle greenhouse benefits of PV power. A summary of recent studies is provided in Table 6.38. Again, a specific review of each study cannot be reported here, but it can be seen that in terms of energy intensity, on average about 2 MJ of primary energy are needed for each kWh of electricity produced, giving energy pay back times of around 4 years. Carbon dioxide emissions produced in the manufacture of PV systems, averaged over the lifetime electricity production of the systems are in the range of 50-200 g CO_2-e/kWh.

Some particular studies of interest are the analysis by Crawford et al. [90] who conduct a study using hybrid process and input-output analysis for Australian conditions, but with a focus on a pure energy analysis, and with the addition of a heat recovery unit on the photovoltaic device for water heating. Voorspools et al. [67] also include input-output analysis in their methodology, but are constrained by a highly aggregated data set, and hence rely purely on process analysis data.

Ref.	Grid connection	Stage	Type	Life-time	Total capacity	Irradiation - annual	Capacity factor	Electricity produced (kWh/year)	Energy intensity (panel w/o frame)	Energy intensity (panel w frame)	Energy intensity (BOS)	Energy intensity total	Green-house intensity
				Yrs	MW^{el}	kWh/m^2	%	kWh/yr	MJ/W_p	MJ/W_p	kWh/m^2	kWh_{th} / kWh_{el}	gCO_2 / kWh_{el}
[91]	GC - PIBV	conceptual	multicrystalline silicon	30		1700			32.0	35.0	500.0		60
[91]	GC - Centralised	conceptual	multicrystalline silicon	30		1700			32.0	35.0	194.4		
[91]	GC - PIBV	conceptual	amorphous-Si	30		1700			17.0	23.0	500.0		50
[91]	GC - Centralised	conceptual	amorphous-Si	30		1700			17.0	23.0	194.4		
[92]	GC - Centralised	hypothetical	multicrystalline silicon	30		"low"		1200					170
[92]	GC - BIPV	hypothetical	multicrystalline silicon	30		"low"		850					120
[93]	GC - BIPV	operational	mc-Si/a-Si mix	25		1580		1300	32.0	35.0	500.0		41.7
[93]	GC - BIPV	operational	amorphous silicon	25		1580			17.0	23.0	194.4		
[94]	OG - BIPV	operational	mono-crystalline silicon		0.0064		5%	10289					
[95]	OG - BIPV	conceptual	not reported	20	0.00028		11%	233.6					
[96]	GC - BIPV	hypothetical	mono-crystalline silicon	25	0.00200		5%	3471					
[96]	GC - BIPV	hypothetical	mono-crystalline silicon	25	0.00200		5%	3471					
[96]	GC - BIPV	hypothetical	mono-crystalline silicon	25	0.00296		5%	5271					
[96]	GC - BIPV	hypothetical	mono-crystalline silicon	25	0.00296		5%	5271					
[90]	GC - BIPV	conceptual	crystalline Silicon	20	0.00015			647	183.3	254.7			
[97]	OG - centralised	conceptual	not reported	20	0.00133	1200	7%	1576					
[97]	OG - BIPV	conceptual	not reported	20	0.00133	1200	7%	1576					
[98]	GC - Centralised	hypothetical	nanocrystalline dye sens'd	20	500	2190			30.4	39.1			29
[99]	OG - BIPV	operational	not reported	20	0.00120	1717	13%	827					
[100]	GC - Centralised	hypothetical	multicrystalline silicon	30	100	1854	6%	1.5E+08					12
[101]	GC - BIPV	operational	mono-crystalline silicon	25	0.00270		9%	2600	57.6			0.82	217
[102]	GC - BIPV	conceptual	mono-crystalline silicon	20	0.00300	1427	8%	3470					21-91
[103]	GC - Centralised	conceptual	CdS/CdTe	20	10	1430	8%		17.5				

[103]	GC - Centralised	conceptual	CdS/CdTe	20	30	1430	10%		13.5			
[103]	GC - Centralised	conceptual	CdS/CdTe	20	100	1430	12%		10.2			
[104]	GC - BIPV	hypothetical	amorphous silicon	20	0.002		6%	3086				51.2
[105]	GC - Centralised	hypothetical	multicrystalline silicon	30	10		10%	8640000				113-132
[106]	GC - Centralised	hypothetical	mono-crystalline silicon	25	5	2000	4%	1.0E+07				
[78]	GC - Centralised	conceptual	not reported	25	3.3		34%					68.6
[58]	GC - Centralised	conceptual	multicrystalline silicon	30	10		15%					53.4
[58]	GC - Centralised	future	multicrystalline silicon	30	1000		15%					43.9
[58]	GC - Centralised	future	amorphous-Si	30	1000		15%					26
[107]	GC - BIPV	operational	mono-crystalline silicon	25	0.0027			2630			0.81	217
[73]	GC - BIPV	conceptual	multicrystalline silicon	25	0.003						0.42	99
[108]	GC - Centralised	conceptual	not reported	30	1			1.2E+06				153
[108]	GC - Centralised	conceptual	not reported	30	10			1.2E+07				148
[108]	GC - Centralised	conceptual	not reported	30	10			8.6E+06				187
[67]	GC - BIPV	conceptual	mono-crystalline silicon	20	1		9%		43.0		0.78	110
[67]	GC - Centralised	conceptual	mono-crystalline silicon	20	1		9%		43.0		0.97	160
[67]	GC - BIPV	near-future	mono-crystalline silicon	25	1		9%		43.0		0.36	50
[67]	GC - Centralised	near-future	mono-crystalline silicon	25	1		9%		43.0		0.47	80
[109]	GC - Centralised	operational	multicrystalline silicon	30	0.4		14%	5.0E+05	43.0		1.0	104
[110]	GC - Centralised	review	not reported									13
[111]	GC - BIPV	conceptual	amorphous-Si	20							0.21	47

Table 6.38: Characteristics and impacts of PV systems (GC = grid-connected, BIPV = building-integrated PV, BOS = balance of system).

6.6.3 Scenario description for PV power

The vast range of photovoltaic devices, module types, applications and outputs under different solar conditions requires a careful selection of PV scenario for the present study. PV modules made from silicon wafer solar cells (crystalline silicon, c-Si) represented 90% of the market share in 2004 [112]. They can be considered a mature technology and although there are many other types of promising PV technologies, modules made with c-Si cells are most appropriate for the purposes here of defining a current realistic scenario for large scale PV systems. c-Si cells can be used in PV power for grid-connected (roof-top and ground mounted), building integrated, and in distributed applications. Multi-crystalline (mc-Si) will be assumed here with a current typical module efficiency of 13% (solar to electric) [112]. Balance of system components such as module support structures, electrical connections to modules, and electrical inverters (to convert from DC to AC electricity) are important for large scale systems, and typically operate at about 85% efficiency [112].

The major processes in the production of PV power are shown in Figure 6.7. The dotted line shows the conventional life cycle boundary. Crawford et al. [90], in a study of energy use in building-integrated PV (BIPV), found that 55% of the energy impact occurred outside the conventional life cycle boundary – i.e. in the indirect impacts. Inside the conventional life cycle boundary, each process is identified separately, and major inputs have been documented. In Figure 6.7 imports for the current Australian PV industry are identified as yellow, whilst domestic production is identified green. However, as with the other technologies in this report all energy and emissions calculations will assume that the systems are made in Australia under Australian-average energy and emissions conditions.

The preliminary process in PV cell involves the production of metallurgical grade silicon from quartz or sand. This is an established process, with representative figures outlined below with respective sources. For the manufacture of metallurgical grade silicon (MG-Si), the material and energy requirement for 1 tonne of MG-Si production are shown in Table 6.39.

Material	**Mass (/ t Si)**	**Reference**
Quartz:	2.8 t	[113, 114]
Coal	0.6 t	[114]
Charcoal	0.4- 0.65 t	[102, 114]
Coke	0.4 - 0.75 t	[113, 114]
Woodchip	0.75-1.4 t	[113, 114]
Energy requirement: electricity	11-15 MWh	[68, 102, 113, 114]

Table 6.39: Material and energy contents for silicon manufacture.

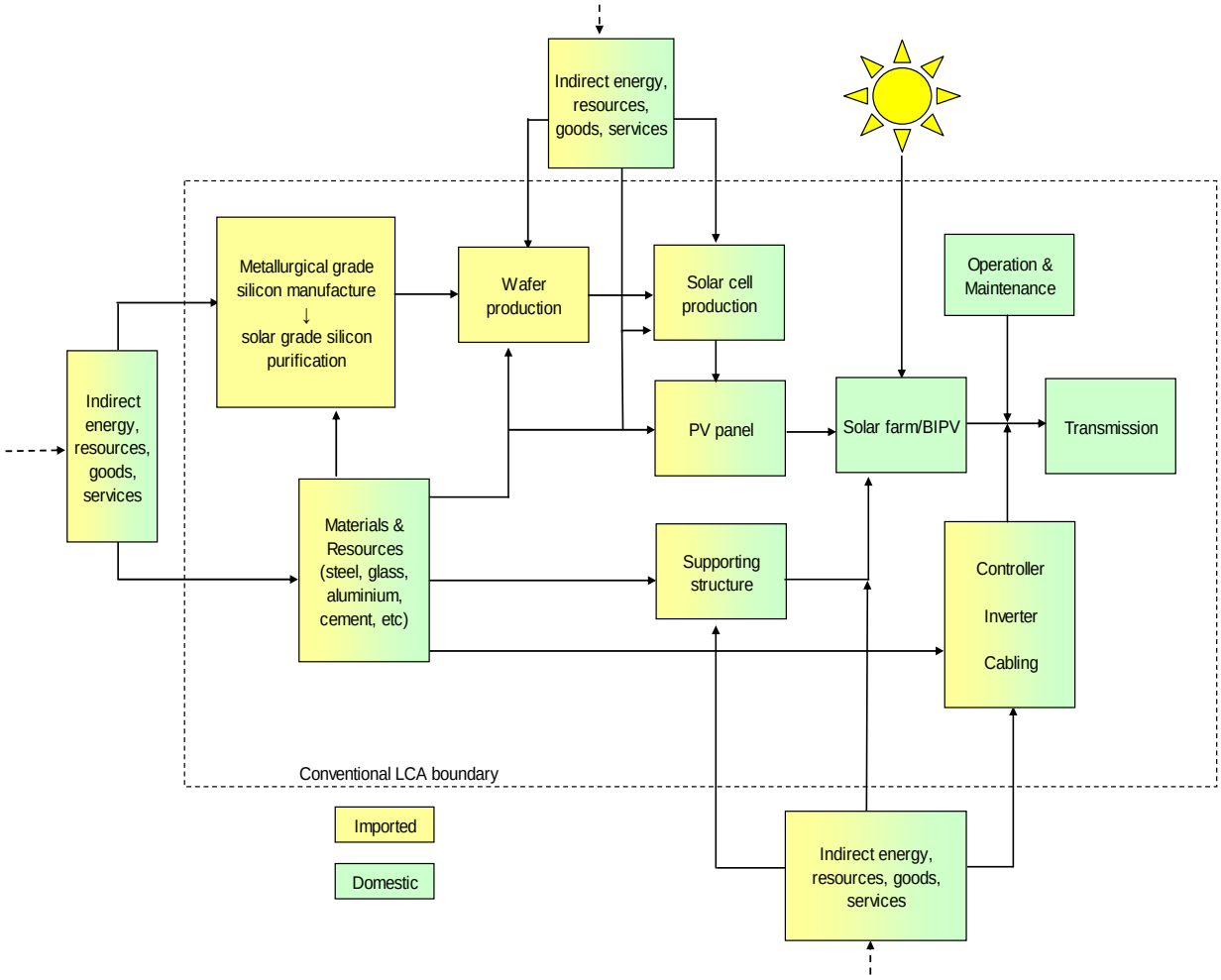

Figure 6.7: Major processes identified in production of PV power.

There are also numerous sources of data on the processes of wafer production and solar cell production. Many of these sources provide differing results, and assess impacts in terms of different parameters. Rather than trying to reconcile different sources of disparate data, the process inventory of the EcoInvent LCA inventory constructed by de Wild-Scholten and Alsema for the European Commission CrystalClear project [115] is used. These authors provide the most recent detailed data for mc-Si PV, using current technology averaged over a number of plants. They cover the processes of solar-grade silicon manufacture, wafer production, solar cell production and solar module production. The data is generally from plants in Western Europe but has been adapted here to apply to the Australian energy system.

Thus the key information source for the module production process is:

- de Wild-Scholten, M. J. and Alsema, E. A. (2005). "Environmental Life Cycle Inventory of Crystalline Silicon Photovoltaic Module Production." Proceedings of the Materials Research Society Fall 2005 Meeting, Symposium G, Boston, USA, 28-30 November 2005, from online publication at: www.mrs.org. [115]

Important LCA inventory data for processes from Si production to modules are presented in Tables 6.40 to 6.44.

Products	Unit	Value	Comment
Polycrystalline silicon, Siemens process	kg	1.00	high purity, with specifications applicable for photovoltaic industry
MG-silicon	kg	1.13	metallurgical grade silicon
Inorganic chemicals, unspecified	kg	2.00	mix of NaOH, HCl and H_2
Heat from natural gas	MJ	185	for process heat
Electricity	kWh	110	actual sources of electricity can vary with considered production location

Table 6.40: Production requirements for solar grade silicon [115].

Products	Unit	Amount	Comment
multi-Si wafer	m^2	1	typical wafer area: 125x125 mm^2 (0.0156 m^2), average thickness 285 um
poly-Si	kg	1.67	polycrystalline silicon of semiconductor or solar grade quality, partly internally recycled silicon from ingot cut-offs and broken wafers
quartz crucible	kg	0.390	for ingot growing
glass	kg	0.01	for temporarily attachment of bricks to wiresawing equipment
steel wire	kg	1.49	for wafer cutting
silicon carbide (SiC)	kg	2.61	for sawing slurry
electricity, medium voltage	kWh	30	total electricity including direct and indirect process energy and overhead energy
natural gas	MJ	4	for removing adhesive after sawing

Table 6.41: Main production requirements for 1 m^2 of multi-crystalline wafer [115].

Products	Unit	Amount	Comment
multi- or mono-Si cell (156 cm^2)		1	cell area 156 cm^2, typical thickness 270-300 um
Water, cooling	m^3	1.56E-02	cooling water
multi/mono-Si wafer (156 cm^2)	p	1.06E+00	
phosphorus paste	kg	2.27E-05	for emitter formation
metallisation paste	kg	1.17E-03	aggregated value for front and back pastes containing, silver content 1.6E-4 kg
polystyrene, expandable	kg	6.36E-06	for packaging
electricity, medium voltage	kWh	5.90E-01	
natural gas	MJ	7.42E-02	
fuel oil	litre	5.06E-04	

Table 6.42: Production requirements for 156 cm^2 solar cell [115].

Products	Unit	Amount	Comment
Module, c-Si	p	1	dimensions see below
Solar cells	p	73.4	+2% cell loss
Aluminium profile	kg	3.8	for frame, may vary per manufacturer
Polyphenylenoxid	kg	0.2	junction box, may vary per manufacturer
Glass sheet, low iron, tempered	kg	11.4	assuming 3.6 mm glass thickness, varies from 3.2 to 4.0 depending on application, size and manufacturer, +1% loss
Ethyl Vinyl Acetate	kg	1.3	EVA consumption 0.96 kg/m^2, +6% more than glass area
Back foil, for solar cell module	kg	0.32	50% polyvinylfluoride, 50% polyethylene terephthalate, 0.243 g/m^2 (0.17 mm thickness) 7% cutting loss
Copper	kg	0.14	copper ribbbons for cell interconnection
Tin	kg	0.007	Sn60Pb40 plating on tabbing material, Sn plating on interconnect/terminal ribbons
Lead	kg	0.004	Sn60Pb40 plating on tabbing material, some manufacturers use lead free.
Nickel	kg	0.00020	Ni plating on interconnect/terminal ribbons
Soldering flux	kg	0.0100	soldering flux, 95% propanol, no halogens
Methanol	kg	0.0162	cleaning fluid 13 ml/m^2
Silicone	kg	0.0029	for diaphragma of laminator
Silicone kit	kg	0.150	kit to attach frame and junction box
Cardboard	kg	1.37	packaging; estimation: 2 modules per cardboard box, 1 kg/m^2 board, 2.2 m^2 board per m^2 module
Electricity	kWh	**8.33**	total process energy

Table 6.43: Production requirements for 1 crystalline silicon PV module [115].

Module parameters	Value	Unit
Number of cells, width:	6	
Number of cells, length:	12	
Cell size (length):	12.5	Cm
Cell area factor:	1	
Cell efficiency (encapsulated)	14.7	%
Module width (w/o frame)	80	Cm
Module length (w/o frame)	156.2	Cm
Module area (w/o frame)	1.25	M^2
Module perimeter (= frame length)	4.7	M
Number of cells:	72	
Module power	165.4	W_p
Module efficiency (glass area, excl. frame)	13.2	%

Table 6.44: Final parameters for Si PV modules [115].

As mentioned above, PV installations require additional materials and systems, so called BOS (balance of system components). The BOS resource requirements for a large scale system appropriate the present study have been well documented by Mason et al in terms of the peak output of a PV system. These are adapted to be consistent with Australian production:

- Mason, J. E., Fthenakis, V. M., Hansen, T. and Kim, H. C. (2005). "Energy Pay-Back and Life Cycle CO2 Emissions of the BOS in an Optimized 3.5 MW PV Installation." *Progress in Photovoltaics: Research and Applications*, in press [116].

Balance of System	**Mass (kg/MW_p)**
PV Support Structure	16821
PV Module Interconnections	453
Junction Boxes	1385
Conduits and Fittings	6561
Wire and Grounding Devices	5648
Inverters and Transformers	28320
Office facilities	20697
Concrete	76417
Miscellaneous	5806
Total	163834

Table 6.45: Balance of system (support structure, controllers, connections) [116].

The final task in defining the PV scenario is to establish the output of the modules under typical operating conditions. Typical values for energy produced by PV modules in Australian conditions are obtained from as 1500-2000 MWh/MW_p per year [88, 89, 117]. A median range figure of 1750 MWh/MW is used as the base case in this study. The full definitions of the cases for the PV scenario are given in Table 6.46. Note that grid losses for PV are assumed lower than the other technologies, due to PV's appropriateness for installation in build up areas, such as green field sites in cities and on factory roofs.

Main parameters	**Base**	**High**	**Low**
Grid losses (%)	3%	5%	0%
BOS efficiency (%)	85%	80%	90%
Module efficiency (%)	13%	12%	14%
Annual electricity (MWh/MW_p)	1750	1500	2000
Module area per peak MW (m^2/MW_p)	9,050	10,417	7,937
Capacity factor (%)	20.0%	17.1%	22.8%
Lifetime (years)	25	20	30
Transport distance (km)	250	400	150
Material intensity factor	1	1.2	0.8

Table 6.46: Main parameters for the PV cases (module rating 1 MW_{el}). The high case corresponds to all parameters leading to high greenhouse intensities.

6.6.4 Energy and emissions intensities

The breakdown of results for a 100 MW_{el} rated PV installation based on the modules and BOS components described above is given below (Table 6.47). Energy use and greenhouse emissions embodied in materials are significant, particularly in the production of silicon cell feedstock, but there are other important contributions as well.

Breakdown	Electricity	Thermal	Total energy		Total emissions	
	(GWh_{el})	(GWh_{th})	(GWh_{th})	(%)	(kt CO_2-e)	(%)
Si production	161.1	75.25	575	44.9%	186.2	41.5%
Module materials	35.2	316.5	352	27.5%	137.9	30.8%
Module production	63.64	2.36	200	15.6%	64.7	14.4%
BOS	13.7	122.9	137	10.7%	53.5	11.9%
Transport	0.0	1.9	1.87	0.1%	0.5	0.1%
Construction	1.0	3.1	4.1	0.3%	2.0	0.5%
Operation	0	10	11	0.9%	3.6	0.8%

Table 6.47: Total full chain results for the base case for PV of 100 MW_{el} rating.

The total greenhouse gas intensity for the PV base case is 106 g CO_2-e/kWh (Table 6.48) with a range of the high and low cases between 53 and 217 g CO_2-e/kWh, which are based on very conservative bounds to the analysis. These results are consistent with those given in Table 6.38 covering 50-200 g CO_2-e/kW.

Case	**Energy intensity**	**Greenhouse gas intensity**	**Lifetime output**	**Comment**
	(kWh_{th}/kWh_{el})	(g CO_2-e/kWh)	(GWh_{el})	
Base	0.33	106	4,244	20.0% capacity factor, 25 year lifetime
High	0.67	217	2,850	17.1% capacity factor, 20 year lifetime
Low	0.16	53	6,000	22.8% capacity factor, 30 year lifetime

Table 6.48: Summary of full chain intensities for 100 a MW_{el} nominal PV installation.

Other more specific and recent results from the literature for comparison (in g CO_2-e/kWh) are ~18 (for BOS of PV) [118], 73 (for Switzerland, but with favourable assumptions about the manufacture of Si) [29], 40-50 (optimistic and method not elaborated) [112], 160 (large scale systems) [67], 171-235 (mid 1990s data, Switzerland) [86], and 104 [73].

The present results are higher than that given in the CCSD case study of the 400 kW Singleton solar farm in NSW (capacity factor of 14%, 30 year lifetime) of 29 g CO_2-e / kWh [109], despite the lower output and older technology assumed in this study.

6.7 Hydroelectricity

There are two main types of hydroelectric conversion technology: reservoir hydropower plants and run-of-river plants. The first type can be quite large in size, up to around 1000 MW for single facilities is common, the limit being mainly imposed by the local topography and the water resource. Given Australia's environmental and climate conditions, significant new capacity in large-scale reservoir hydroelectricity is unlikely and will not be considered here. Run-of-river hydroelectricity in contrast is usually at a smaller scale (approximately 200 MW_{el} maximum) and its application under different conditions is more flexible. Despite this, there is no significant, large run-of-river hydroelectric capacity in Australia.

There are two main energy-related issues and sources of emissions for the establishment of hydro power. One is due to the materials embodied in the construction (substantially concrete), with lifetimes often of up to 100 years, which is usually the time used in many analyses. The second concerns the release of greenhouse gases due to changes in the use of land, primarily relating to the rotting of vegetation and subsequent release of greenhouse gases. One example of this is the flooding of valleys to create large reservoirs which could lead to biomass decay and emissions of up to 400 g CO_2-e/kWh [119]. These second types of emissions can largely be ignored for the run-of-river systems considered here

A selection of literature values for the greenhouse intensity of hydro electricity is shown in Table 6.49. It can be seen that although there is quite a range, hydro power is still a relatively low emissions form of electricity.

Reference	**Comment**	**g CO_2-e/kWh**
Gagnon et al 2002 [110]	Reservoir	15
Gagnon et al 2002 [110]	Run-of-river	2
EcoInvent report [16]	Reservoir	5-34
EcoInvent report [16]	Run-of-river	3
Dones and Gantner [119]	Swiss run-of-river	3.7
Dones and Gantner [119]	Swiss reservoir	4.5
Van de Vate [84]	Small run-of-river	1-3
Van de Vate [84]	Small reservoir with concrete	10-40
Van de Vate [84]	Large concrete reservoirs	1-5
Vattenfall hydro [120]	Large concrete reservoirs	~4.5 (inundation = 3)
Chamberland et al [121]	Quebec hydro	57

Table 6.49: Energy and greenhouse intensity summary for hydroelectricity.

For the purposes of developing a scenario for this report, the material and energy inventory of Dones and Gantner is used, and modified to be appropriate with Australia's current energy mix [119]. Specific sites and local conditions are not accounted for and it is assumed that Dones and Gantner's average figures for all low pressure run-of-river hydroelectric systems in Switzerland are suitable for Australia. Lower capacity factors however are assumed, and all material and energy requirements are calculated from the gross capacity of the Swiss systems, not on their energy outputs. Conservative lifetime and conversion efficiency figures have been used. The main assumptions for the three cases are given in Table 6.50.

Main parameters	Base	High	Low
Grid losses (%)	5%	9%	3%
Generation efficiency (%)	82%	77%	87%
Capacity factor (%)	50%	35%	65%
Lifetime (years)	40	25	55
Transport distance (km)	250	400	150
Material intensity factor	1	1.2	0.8

Table 6.50: Main parameters for the hydroelectric cases.

The breakdown of results for a 100 MW_{el} rated run-of-river hydroelectricity installation based on the assumptions made above is given below (Table 6.51). Energy use and greenhouse emissions embodied in materials are not significant compared with the output of the system.

Breakdown	Electricity	Thermal	Total energy		Total emissions	
	(GWh_{el})	(GWh_{th})	(GWh_{th})	(%)	(kt CO_2-e)	(%)
Materials	48.3	434.5	483	72.0%	189	76.0%
Transport	0.0	16.0	16	2.4%	4	1.8%
Construction	29.5	80.0	171	25.6%	55	22.3%

Table 6.51: Total full chain results for the base case of 100 MW_{el} of hydroelectricity.

The total greenhouse gas intensity for the hydroelectricity base case is 15 g CO_2-e/kWh (Table 6.52) with a range of the high and low cases between 6.5 and 44 g CO_2-e/kWh, which are based on very conservative bounds to the analysis. These results are consistent with those given in Table 6.49 covering 3-40 g CO_2-e/kW.

Case	Energy intensity	Greenhouse gas intensity	Lifetime output	Comment
	(kWh_{th}/kWh_{el})	(g CO_2-e/kWh)	(GWh_{el})	
Base	0.046	15	16,644	50% capacity factor, 40 year lifetime
High	0.137	44	6,975	35% capacity factor, 25 year lifetime
Low	0.020	6.5	30,377	65% capacity factor, 55 year lifetime

Table 6.52: Summary of full chain intensities for a 100 MW_{el} nominal hydroelectric installation.

6.8 Summary of results: non-nuclear generation

A range of non-nuclear electricity generation technologies have been analysed. These technologies have widely varying electricity output and resource requirements, requiring careful definitions of meaningful base scenarios and high and low bounds. The typical estimates are suitable for comparisons between technologies for Australian conditions. The results are summarised below.

Technology	**Typical**		**Min**	**Max**
	kWh_{th}/kWh_{el}	**g CO_2-e/kWh**	**g CO_2-e/kWh**	**g CO_2-e/kWh**
Black coal PF fuel (Table 6.12)	2.85	941	843	1171
Black coal supercritical (Table 6.15)	2.62	863	774	1046
Brown coal subcritical (Table 6.20)	3.46	1175	1011	1506
Natural gas turbine – open cycle (Table 6.27)	3.05	751	627	891
Natural gas – combined cycle (Table 6.29)	2.35	577	491	655
Wind power (Table 6.36)	0.066	21	13	40
Photovoltaic generation (Table 6.48)	0.33	106	53	217
Hydro power (Table 6.52)	0.046	15	6.5	44

Table 6.53: Greenhouse intensity summary for the non-nuclear technologies.

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7 Conclusions

This report presents in a condensed yet comprehensive way a large body of previous work and knowledge about the energy balance and life-cycle greenhouse gas emissions associated with the nuclear fuel cycle.

Certainly, every practical life-cycle assessment is undertaken for particular circumstances, that is particular locations, ores, or reactor types. Results must therefore be interpreted as valid for these circumstances. Changing critical parameters and assumptions will lead to variations of the results.

Also, every practical life-cycle assessment leaves out some more or less important part of a theoretically "true" life-cycle, be it parts of the fuel cycle processes, indirect, upstream inputs into components, or parts of the material fuel and waste stream. In bringing together analyses that are all incomplete with regard to a different aspect of the nuclear fuel cycle, and in extrapolating the results from these analyses towards a more complete "integrated" assessment, this work has achieved comparisons between nuclear energy systems that are very different in terms of a large number of critical technical parameters, operate in low- and high-carbon economies, and are assessed using different methods.

7.1 Methodology and data

The project team believes that the hybrid, input-output-based life-cycle assessment method is the most appropriate one to use for the analysis of energy and greenhouse gas emission balance of the nuclear fuel cycle. The procedure to be followed has been outlined in the pioneering work of Bullard and co-workers [1], with a recent position paper published by the world-leading institutions in the field [2]. The essence of a hybrid input-output-based life-cycle assessment is to undertake an input-output analysis of the functional unit (here: the nuclear fuel cycle in Australia), then to identify top-ranking contributions, and replace those by superior process data wherever available [3].

A life-cycle assessment of the nuclear fuel cycle in Australia requires a) specifications and data on the mining, milling, enrichment, power generation, storage and disposal facilities, and b) data on the background economy supporting such a nuclear industry indirectly. An Australian nuclear fuel cycle is – except for mining and milling – hypothetical, and has been constructed based on the best knowledge and overseas experience available. Ideally, a more detailed life-cycle assessment than the one carried out in this work would exploit detailed planning and engineering data for concrete Australian facilities, in conjunction with an Australian input-output database.

The reliability of an input-output-based life-cycle assessment relies critically on the quality of the underpinning input-output data. In particular, given that hybrid input-output-based life-cycle assessment is the internationally accepted standard for investigating resource issues, it is essential that Australia possesses an input-output database that

- is updated annually;
- distinguishes industries and commodities at a high level of detail, that is more than 200 industries and commodities, respectively;
- distinguishes environmentally important industries and commodities, such as within agriculture, mining, and basic metals and chemicals manufacturing;
- is consistent in its classification between the years, and applicable as a time series for trend analysis;
- contains capital flow tables;
- is available at the State level.

None of these requirements are fulfilled to date. For the specific application to the nuclear fuel cycle, the requirement for capital flow tables is perhaps amongst the more important, since the Australian power generation industry allocates 36% of its expenditure on capital items [4]. Long-term capital flows are often not considered in hybrid input-output applications because of the lack of data [5-8].

This study has provided an example that demonstrates both the strength of the state-of-the-art life-cycle method in informing national policy, and the need for quality data underpinning this method.

7.2 Assumptions and scope of this life-cycle analysis of nuclear energy in Australia

The energy requirements for **mining and milling** as well as the **recovery rate** depend critically on the grade of the uranium-bearing ore, and on whether uranium is mined together with other products. In this study we have assumed that uranium is recovered from ore of 0.15% grade (typical grade for Ranger and Beverley mines), and that no other product is mined, so that the full energy requirement is attributable to uranium. This is a conservative assumption, because had we assumed conditions as in the Olympic Dam mine, the ore grade would have been lower (around 0.05%), however most energy requirements would have been attributable to the recovered copper [9-11].[1] For the calculation of the recovery rate we have used the regression formula by Storm van Leeuwen and Smith (Eq. 2.2 in [13]).

The energy requirements for **enrichment** depend critically on which enrichment method is employed. In this study we have assumed the present mix of diffusion and centrifuge plants (30/70%). For future scenarios this is a conservative assumption (in agreement with [13]), because it is expected that in the future centrifuge plants will substitute diffusion plants.

The energy requirements for the **construction, operation and decommissioning** of nuclear facilities depend critically on what method is used for their enumeration. We have based this study on input-output hybrid life-cycle assessments [2, 14-16], notably references [17, 18]. We discard findings based on the method of multiplying overall cost with economy-wide energy and greenhouse gas intensities [13, 19-21],

[1] BHP Billiton [12] states that "in most situations where uranium is mined together with a by-product, the by product occurs in higher concentrations and amounts than uranium." Under these circumstances, most of the mining energy is apportionable to the by-product.

because of the inherent aggregation error [22] and double-counting (see Sections 2.9 and 3.6, and [23, 24]).

The energy requirements for **mine clean-up**, **intermediate storage and long-term disposal** of nuclear waste depend critically on which procedures are deemed acceptable for sufficiently isolating radioactivity from the natural and human environment. At present, there is no operating final disposal facility, and hence limited practical experience of containing radioactivity for very long periods. This study does not comment on the adequacy of existing and planned mine clean-up, storage and disposal procedures (for example [25, 26]), because these aspects fall outside this study's scope. We discard estimates for energy requirements of storage and disposal calculated by multiplying overall costs with economy-wide intensities, on methodological grounds outlined in Section 3.6. We also discard as an outlier Storm van Leeuwen and Smith's estimates for energy requirements of mine-clean up and disposal (see Section 5.1.6).

The **lifetime of uranium resources** for supplying the world's nuclear power plants depends critically on assumptions about future electricity demand, recoverable resources and ore grade distributions [27-32], by-products of uranium in mines, future exploration success [33, 34], the exploitation of breeder reactors and plutonium in MOX fuels, and market conditions [28, 32]. These aspects are outside the scope of this study.

7.3 Overall results for the nuclear fuel cycle

The energy balance of the nuclear fuel cycle involves trade-offs between material throughput and fissile isotope concentration at various stages in the cycle (see [18] p. 43). For example, there are trade-offs between

- using less but enriched fuel in Light Water Reactors, versus more but natural fuel in Heavy Water or Gas-cooled Graphite Reactors,
- applying more enrichment work to less fuel, versus less enrichment work to more fuel, and
- investing more energy into uranium and plutonium recycling, versus higher volumes of fuel uranium mining, throughput, storage, and disposal.

The overall energy intensity of nuclear energy supply systems depends critically on

- the grade of the uranium ore mined,
- the method for enrichment,
- the conversion rate of the nuclear fuel cycle (i.e. fuel recycling).

The overall energy intensity will increase

- with decreasing uranium ore grades,
- with increasing proportion of diffusion plants, and
- with decreasing fuel recycling.

Notwithstanding these variations, it can be stated that

- accepting the qualifications and omissions stated in Section 7.2,
- for grades of average ore bodies mined today, and
- for state-of-the-art reactors and uranium processing facilities,

the energy intensity of nuclear power

- is around 0.18 kWh_{th}/kWh_{el} for light water reactors, and around 0.20 kWh_{th}/kWh_{el} for heavy water reactors,
- is slightly higher than most figures reported in the literature, because of omissions in the nuclear fuel cycle and upstream supply-chain contributions,
- varies within the range of 0.16-0.4 kWh_{th}/kWh_{el} for light water reactors, and within 0.18-0.35 kWh_{th}/kWh_{el} for heavy water reactors,
- is lower than that of any fossil-fuelled power technology.

Energy payback times are around 6½ years for light water reactors, and 7 years for heavy water reactors, ranging within 5.6-14.1 years, and 6.4-12.4 years, respectively.

The greenhouse gas intensity of nuclear energy supply systems depends critically on

- the energy intensity,
- the proportion of electric versus thermal energy in the total energy requirement,
- whether electricity for enrichment is generated on-site (nuclear), or by fossil power plants, and
- the overall greenhouse gas intensity (i.e. fuel mix) of the economy.

The overall greenhouse gas intensity will increase

- with increasing energy intensity,
- with increasing proportion of electricity in the energy requirement,
- with increasing proportion of electricity for enrichment generated by fossil power plants, and
- with increasing greenhouse gas intensity of the economy.

Similarly,

- accepting the qualifications and omissions stated in Section 7.2,
- for grades of average ore bodies mined today, and
- for state-of-the-art reactors and uranium processing facilities,

the greenhouse gas intensity of nuclear power

- around 60 g CO_2-e/kWh_{el} for light water reactors, and around 65 g CO_2-e/kWh_{el} for heavy water reactors,
- slightly higher than most figures reported in the literature, because of omissions in the nuclear fuel cycle and upstream supply-chain contributions,
- varies within the range of 10-130 g CO_2-e/kWh_{el} for light water reactors, and within 10-120 g CO_2-e/kWh_{el} for heavy water reactors,
- lower than that of any fossil-fuelled power technology.

7.4 Results for non-nuclear electricity technologies

A comprehensive literature review and application of current energy and greenhouse parameters for Australian conditions has been undertaken for traditional fossil-fired electricity technologies and several mainstream renewable technologies. The Australia-specific energy and greenhouse intensities developed have been calculated using comparable assumptions and procedures as for the nuclear energy analysis. A summary of all the results is presented in the table below.

Electricity technology	Energy intensity (kWh_{th}/kWh_{el})	Greenhouse gas intensity (g CO_2-e/kWh_{el})
Light water reactors	0.18 (0.16 – 0.40)	60 (10 – 130)
Heavy water reactors	0.20 (0.18 – 0.35)	65 (10 – 120)
Black coal (new subcritical)	2.85 (2.70 – 3.17)	941 (843 – 1171)
Black coal (supercritical)	2.62 (2.48 – 2.84)	863 (774 – 1046)
Brown coal (new subcritical)	3.46 (3.31 – 4.06)	1175 (1011 – 1506)
Natural gas (open cycle)	3.05 (2.81 – 3.46)	751 (627 – 891)
Natural gas (combined cycle)	2.35 (2.20 – 2.57)	577 (491 – 655)
Wind turbines	0.066 (0.041 – 0.12)	21 (13 – 40)
Photovoltaics	0.33 (0.16 – 0.67)	106 (53 – 217)
Hydroelectricity (run-of-river)	0.046 (0.020 – 0.137)	15 (6.5 – 44)

Electricity generated by wind turbines and run-of-river hydroelectricity has greenhouse gas intensities lower than those for nuclear technologies. The other technologies show a range of values, with traditional pulverised fuel black coal generation having approximately fifteen times higher greenhouse gas intensity than for the nuclear technologies.

7.5 The need for further analysis

A final qualification of the above conclusions should be made: It has been pointed out previously that comparative energy and greenhouse gas emissions analyses of energy supply systems are not a substitute for, but a supplement to economic, social, and other environmental considerations ([35]; Box 7.1). For instance, if an energy supply system can be shown to a clear energy loser, then energy analysis is sufficient to argue that the program should be abandoned. If, on the contrary, the system appears to be an unambiguous energy producer, the decision whether or not to proceed with the program must also be based on other criteria ([35-39]; see also the ExternE study [40], [41], and [42] p. 37).

> "*The net analysis of one or more systems having been completed, and several measures of net energy yield being at hand, there remains the significant question of how this information is to be used. One possibility is to compare one system with another. Another possibility is to supplement an engineering economic analysis.*
>
> *We do not believe that it is <u>generally</u> possible to compare or rank-order dissimilar energy technologies on the basis of net energy indexes. Issues of resource availability may be more important in many situations. […]*
>
> *It is possible, nevertheless, to regard a net energy estimate as a kind of minimum criterion for acceptability. If the system clearly yields net energy, then decisions to proceed with development and deployment should be based on other considerations.*"

Box 7.1: Conclusions from net energy analysis (from [16], pp. 66-68).

7.6 Further observations

1. Most previous life-cycle studies documented in the literature use static methods that do not take into account temporal profiles of energy sources and sinks occurring in the nuclear fuel cycle, and the temporal interplay of net supply and demand for electricity. The current study could be enhanced by

- developing a dynamic formulation of a time-dependent profile of energy supply from a mix of sources;
- undertaking a long-term forecasting exercise of the transition of Australia's electricity generating system to a new mix of nuclear, advanced fossil, and renewable technologies, and the economy-wide TBL implications thereof.

In order to avoid multiple counting (as outlined in Section 2 of this report), the energy supply system could be examined in conjunction with the entire economy in which it is embedded.

2. In order to enable sound life-cycle assessments of the implications of nuclear energy for our environment, our physical resource base, and our society, it is essential that they are underpinned by a detailed and complete information base. Australian life-cycle assessment capability would benefit from an enhanced data collection effort at the national level, in particular with view to creating a seamlessly aligned input-output database that

- is updated annually;
- distinguishes industries and commodities at a high level of detail, that is more than 200 industries and commodities, respectively;
- distinguishes environmentally important industries and commodities, such as within agriculture, mining, and basic metals and chemicals manufacturing;
- is consistent in its classification between the years, and applicable as a time series for trend analysis;
- contains capital flow tables;
- is available at the State level.

3. Following from Section 7.5, nuclear energy scenarios for Australia would benefit from an extended multi-criteria life-cycle analysis incorporating additional social, economic and environmental indicators spanning the entire Triple Bottom Line (compare with new developments in the ExternE project of the European Commission [43-45]).

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Project team

Prof Marcela Bilek

Marcela was appointed Professor of Applied Physics at the University of Sydney in November 2000. She was awarded a Federation Fellowship in 2003. She holds a PhD in Engineering from the University of Cambridge, UK, a B.Sc.(Hons) in Physics from the University of Sydney and an MBA degree from the Rochester Institute of Technolgy, USA,. Prior to her present appointment she held a visiting Professorship at the Technische Universitat Hamburg-Harburg in Germany and a Research Fellowship at Emmanuel College, University of Cambridge, UK. She also worked for a number of years as a visiting Research Scientist at the Lawrence Berkeley Laboratory, University of California, USA. Aside from her academic experience, Marcela has spent time working in industry as a Research Scientist at Comalco Research Centre, Melbourne, and at the IBM Asia Pacific Group Headquarters in Tokyo, Japan.

In her current appointment, Marcela leads a large research group specializing in materials and energy related technologies. In addition to leading a number of large Australian Research Council research projects, she is responsible for major industry sponsored projects on highly insulating glazing for energy efficient architecture and selective surfaces for solar power applications. She has received a number of prestigious prizes for her work including the Malcolm McIntosh Prize for Physical Scientist of the Year in 2002, an MIT TR100 Young Innovator award in 2003 and the Australian Academy of Science Pawsey Medal in 2004.

Marcela has represented the ISA group at high-level events, and is co-author of international journal articles and government submissions on life-cycle Triple Bottom Line Accounting.[1] She serves on the Australian Radiation Protection & Nuclear Safety Agency (ARPANSA) Nuclear Safety Committee, Heliac H-1 National Fusion Facility Advisory Board, and the Australian Academy of Sciences National Committee for Physics.

[1] Dey *et al.* 2002; Foran *et al.* 2005

Dr Manfred Lenzen

Manfred is an international leader in life-cycle assessment. He has contributed major methodological advances as well as numerous applications, in particular on embodied energy and greenhouse gas emissions, and on transport modes.

Manfred has authored a number of publications that demonstrate the need to complement process analyses with input-output analysis, into a hybrid method. Manfred has also authored a number of applications that demonstrate the severity of truncation errors in process-based studies.[2]

In 2001, Manfred has worked with wind energy experts in Denmark in order undertake an international review of energy and greenhouse gas analyses of wind turbine technologies.[3] The scope of that study was very similar to the scope of the study on nuclear energy outlined here, because it combined methodological aspects of life-cycle assessment with technological aspects of wind turbines.

Manfred has 15 years of experience in nuclear radiation science. He has a PhD in Nuclear Physics from the University of Bonn, Germany. He has been commissioned by the German Federal Parliament to undertake a study to evaluate the links between the proximity of nuclear reactors and leukaemia incidents.[4] At the time, this study was publicised in the German media.

Manfred has undertaken numerous studies on nuclear detector technology, and on the correlations and effects of nuclear radiation from Radon in the environment, both in Germany and Australia.[5]

In 2000, Manfred received a grant from the Australian Institute of Nuclear Science and Engineering (AINSE) to undertake a research project at the Australian Nuclear Science and Technology Organisation (ANSTO).[6] In 2001, Manfred met with Prof Yohji Uchiyama, leader of the Japanese life-cycle analysis program for nuclear energy, at the Central Research Institute of the Electricity Producing Industry in Ohtemachi, Tokyo.

Manfred also has 15 years of experience in renewable energy technologies. He has undertaken extensive experimental research on passive solar architecture and solar collector technology.[7] He has previous experience in consulting government on aspects of energy conservation programmes.[8] At present, Manfred is involved in consulting the Federal Department of Environment and Heritage on the performance of selected renewable energy technologies across the Triple Bottom Line.

In 1999, Manfred has undertaken a review of the energy and greenhouse gases cost of solar-thermal power generation, including a literature review on hydro-electricity, photovoltaics, nuclear power, and fossil-fuelled power.[9]

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[8] Lohr *et al.* 1991
[9] Lenzen 1999

Dr Clarence Hardy

Clarence James Hardy was born in Derby, England. He received the degrees of BSc (Hons, Chemistry) in 1952 and PhD in 1955 from the University of Bristol. He worked at the Atomic Energy Research Establishment of the UK Atomic Energy Authority at Harwell from 1955 to 1971, and was seconded to work at the Oak Ridge National Laboratory in the USA from 1965-66 on advanced nuclear fuel fabrication processes. In 1966 he was appointed as the leader of the Chemical Processing Group in the Chemistry Division at Harwell, and was responsible for research and development of new nuclear fuel processes and on contract research on applications of nuclear technology in non-nuclear industries. He was awarded the degree of DSc by the University of Bristol in 1971 for over 50 scientific papers and patents in nuclear science and technology published from 1956-1971.

Dr Hardy was appointed in 1971 as Chief of the new Chemical Technology Division of the Australian Atomic Energy Commission (AAEC) at Lucas Heights near Sydney. He then became Program Manager, Uranium Fuel Cycle (1974-77), Chief Scientist, Nuclear Fuel Cycle (1977-83), and Chief, Isotope Division (1983-87), and published a further 50 papers in the nuclear field from 1971-1987. He was Chairman of the Steering Committee of the International Alligator Rivers Analogue Project under the auspices of the OECD Nuclear Energy Agency from 1987-1991.
When the AAEC was replaced by the Australian Nuclear Science & Technology Organisation (ANSTO) in 1987, Dr Hardy was appointed Director, Industrial Technology Program, and Director, Tracerco Australasia (a Joint Venture by ANSTO and ICI Australia). Since retiring from ANSTO in 1991, he has undertaken private consulting in industrial and nuclear technology, public relations and conference management for companies in Australia, Canada, France, the UK and the USA.
Dr Hardy is the Secretary (and a former President) of the Australian Nuclear Association (ANA), a non-profit non-government Scientific Institution with voluntary officers. He is also Editor of its bi-monthly newsletter 'Nuclear Australia'. His book 'Enriching Experiences: Uranium Enrichment in Australia, 1963-1996' was published in 1996 and his history of the AAEC 'Atomic Rise and Fall - The AAEC, 1953-1987' was published in 1999 both by Glen Haven Publishing.

Dr Hardy was Executive Chairman of six national and two international conferences hosted by the ANA - the 9th Pacific Basin Nuclear Conference, Sydney, 1994; the Second International Conference on Isotopes, Sydney, October 1997; National Conferences on Nuclear Science & Engineering in Sydney, 1995; Sydney, 1997, 2001 and 2005 and Canberra, 1999 & 2003. Dr Hardy has been appointed Executive Chairman for the 15th Pacific Basin Nuclear Conference to be held in Sydney in October 2006. Dr Hardy was given the Annual Award of the ANA in 1997 for his outstanding contributions to informing the public on nuclear science and technology and for organising the ANA's major national and international conferences.

Dr Hardy has given over 100 technical talks on many aspects of nuclear science and technology to scientific audiences, government inquiries, public interest groups and schools nationally and internationally since 1971. He is currently a member of special Working Groups on Radioactive Waste Management set up by the Pacific Nuclear Council and by the International Nuclear Societies Council. The ANA was a Founder Member of these non-profit non-government organisations which have voluntary members. He is also the Leader of a new Task Force set up by the PNC to review and report on "Public Information and Education in Nuclear Science and Education in the Pacific Basin".

Dr Hardy was elected in 2002 as a Member of the International Nuclear Energy Academy, an Academy of 100 distinguished international nuclear scientists and in 2003 as Vice-President / President Elect of the Pacific Nuclear Council which represents over 60,000 professionals in 10 countries in the Pacific Basin and which approves the host organisation for its biennial international conferences. Dr Hardy will become President of the PNC for a two-year term from October 2006.

Dr Christopher Dey

Christopher has twelve years experience in energy analysis, renewable energy technologies and greenhouse gas analysis. Some relevant publications include in solar technology[10], energy and greenhouse analysis[11], and input-output analysis applied to energy and environmental assessment[12].

In 2002 he was awarded an Australian Postdoctoral Fellow – Industry, within an ARC Linkage Grant "Multi Tower Solar Array (MTSA) for combined heat and power applications in urban areas". Between 1999-2002, Christopher was a chief investigator in a project examining the heat transfer performance of large solar thermal arrays, funded by the NSW Department of Energy's "Sustainable Energy Research and Development Fund". The technology is now being commercialized on a significant (MW) scale in NSW.

1999-2000, Christopher was a key member of an industry-aligned team successful in gaining an Australian Greenhouse Office (AGO) Renewable Energy Showcase Grant ($2M) with Stanwell Corporation for the demonstration of solar thermal technology originating from the School of Physics.

At present, Christopher is consulting to the Federal Department of Environment and Heritage on the Triple Bottom Line performance of renewable energy technologies.

Christopher's PhD was in heat transfer applied to energy conservation devices, and involved extensive industry interaction. He teaches energy, climate science and environmental courses at the University of Sydney. He is also Acting Director of the University of Sydney's Institute for Sustainability, a new cross-disciplinary initiative by the University.

[10] Royne et al 2005, Dey 2004, Mills and Dey 2001a
[11] Lenzen and Dey 2000, Mills and Dey 2001b
[12] Lenzen and Dey 2002, Foran et al 2005