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Economic Evaluation of Alternative Nuclear Energy Systems

Supplement for the INPRO ASENES Service

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ECONOMIC EVALUATION OF ALTERNATIVE NUCLEAR ENERGY SYSTEMS

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SUPPLEMENT FOR THE INPRO ASENES SERVICE

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FOREWORD

The International Project on Innovative Nuclear Reactors and Fuel Cycles (INPRO) was launched in November 2000 under the aegis of the IAEA. Since then, INPRO activities have been regularly endorsed by the IAEA General Conference and by the General Assembly of the United Nations. The objectives of INPRO are to help ensure that nuclear energy contributes to meeting energy needs in the twenty-first century in a sustainable manner and bring together technology holders and users so they can jointly consider the international and national action required to achieve innovation in nuclear reactors and fuel cycles.

The objective of Global Scenarios — a task outlined in INPRO Action Plan 2014–2015 — is to develop global and regional nuclear energy scenarios that help to outline a global vision of sustainable nuclear energy development in this century and beyond. Special scientific–technical analysis tools need to be developed and used to formulate such scenarios. Within this task, several collaborative projects have been implemented to support it, such as nuclear energy scenario modelling and analysis, comparative evaluation of nuclear energy system alternatives and setting out a road map for enhanced nuclear energy sustainability. The valuable experience accumulated while conducting these activities is now being shared with Member States through an INPRO service entitled Analysis Support for Enhanced Nuclear Energy Sustainability (ASENES).

ASENES includes an economic evaluation of nuclear energy system alternatives. This evaluation focuses on the analysis of the competitiveness of different nuclear energy system options. The nuclear energy system assessment economics support tool, initially developed to support nuclear energy system sustainability assessments using INPRO methodology, is used as a basis for the evaluation. The tool was expanded to include the analysis block, making it possible to compare economic indicators and their components for different nuclear technologies or even for nuclear energy systems as a whole.

This publication complements the ASENES service which further elaborates the INPRO methodology in economics and provides information on performing comparative economics evaluations of nuclear energy systems and scenario alternatives. It also specifies the limits for meaningful application of the economic approaches and formulas in the publication. The supplementary files, available on-line, contain an overview of the tools used for economic evaluation.

The IAEA wishes to thank all the contributors to the drafting and review of this publication. The IAEA officers responsible for this publication were V. Kuznetsov and G. Fesenko of the Division of Nuclear Power and A. Gritsevskyi of the Division of Planning, Information and Knowledge Management.

CONTENTS

1. INTRODUCTION

1.1. BACKGROUND

The assessment of sustainability of alternative nuclear energy systems encompasses a wide range of aspects. INPRO has classified seven main areas for assessment of a Nuclear Energy System (NES) among which economics is a critical area for evaluation of nuclear power reactors and their associated fuel cycle technologies. The INPRO basic principle established for this area is: “energy and related products and services from an NES shall be affordable and available” [1]. If an NES is available, or could become available, only then a country or utility would consider it as an option for meeting future energy needs. Secondly, the proposed NES needs to be affordable, implying that it is to be competitive with other energy supply options. Only an NES that is competitive with alternative options would attract investment and would possibly be deployed. As such, for economic sustainability in the long run, a proposed NES is to fulfil four users’ requirements of the INPRO methodology [1]:

(i) “The cost of energy supplied by nuclear energy systems, taking all relevant costs and credits into account … should be competitive with that of alternative energy sources … that are available for a given application in the same time frame and geographic region/jurisdiction.
(ii) The total investment required to design, construct, and commission nuclear energy systems, including interest during construction, should be such that the necessary investment funds can be raised.
(iii) The risk of investment on an NES should be acceptable to investors.
(iv) Innovative nuclear energy systems should be compatible with meeting the requirements of different markets.”

The first user requirement means that taking into account all costs and benefits of the proposed NES, it needs to be competitive with alternatives which could be available. The competitiveness of an NES does not necessarily mean that the NES is the cheapest option on cost basis. All the costs and benefits, monetary as well as non-monetary, have to be accounted for providing the same products and services expected from the NES. As such, for economic evaluation of a nuclear energy project, all the costs and benefits need to be estimated and compared. It is expected that there would be significant uncertainties in the estimates of costs and benefits. A deep understanding of all costs and benefits is, therefore, needed to develop a sound economic evaluation.

The second users’ requirement reflects the affordability of the investment. Since nuclear power is capital intensive, the affordability of its investment becomes important. The overall capacity to invest varies from country to country. If the size of a country’s economy is equivalent to a few tens of billion dollars, it cannot afford a multi-billion dollars nuclear power project. As such, it is vital to ensure that the total investment on the proposed NES could be arranged by the country.

It is well recognized that every project carries some risks related mostly to technical, management, regulatory and external factors. A nuclear power project is typically a large-scale project with a long gestation period and a long operating life. Even after the end of operation, the project life cycle continues till decommissioning and dismantling of the facility. Such projects face significant uncertainties in preparing estimates of their costs and benefits. In the past, several nuclear power projects have experienced long construction delays and large cost overruns, and some plants have not operated as expected, resulting in severe adverse impacts on the economics of the projects. The potential investors would perceive such risks as unacceptable unless adequately compensated. Strengthening competence, better planning and management, streamlining regulatory process and innovation can reduce the risks.

As the energy/electricity markets are being restructured everywhere, the proposed nuclear power project would have to compete and survive in the changing market conditions. Furthermore, with increasing emphasis on renewable energy sources, which are inherently of intermittent nature, the need for higher flexibility in the system is increasing. Nuclear power plants offer rather limited flexibility. A system-wide economic evaluation of the proposed NES in the competitive markets is needed.

Furthermore, with increasing realization of the importance of environmental impacts and climate change effects of various energy options, it is becoming crucial to internalize the cost of damages caused by each energy technology in their economic comparison. Nuclear power has already internalized, to a large extent, the possible adverse impacts of radioactive as well as non-radioactive wastes and releases through strict regulations. This is not the case for other forms of energy technologies.

For conducting a comprehensive economic evaluation of a nuclear energy system and its alternatives a sound methodological approach is needed. The specific technical aspects of various nuclear energy systems have to be taken into account for a sound economic evaluation. INPRO has developed such a methodology together with a set of tools that allows to take into account the important technical and economic characteristics of nuclear power reactors and their associated fuel cycle technologies and can help conduct economic evaluation of alternative nuclear energy systems. A deep understanding of the technical aspects of nuclear energy systems and the basic economic concepts is a prerequisite for conducting economic evaluation.

1.2. OBJECTIVE

The main purpose of this publication is to provide an understanding of the basic concepts and techniques for conducting economic evaluation of nuclear energy system alternatives. It supplements the publications on INPRO Methodology for the area of economics. The economic concepts presented in this publication are generic but central to economic evaluation of alternative projects. The INPRO tool NEST for economic evaluation of nuclear energy systems is based on these concepts. As such, familiarity with these concepts is important for understanding and interpreting the results of NEST. This publication is also intended to highlight the important aspects that are beyond the scope of NEST-based economic evaluation of NES, like power system effects, environmental and external costs and macroeconomic impacts, which need to be included in a realistic economic comparison of nuclear energy systems with other alternative.

The target audience is professionals working at government planning departments, electricity utilities, academic institutions, etc., engaged in evaluation of nuclear and alternative energy options. It can also be used by nuclear technology developers for understanding the economic competitiveness of their proposed nuclear energy systems compared with alternative energy options. This publication could be particularly useful for technical professionals who may have limited familiarity with economics but are interested in and/or involved in assessment of nuclear energy systems using INPRO methodology and tools.

1.3. SCOPE

This publication explains the basic concepts of economics relevant for analyzing economic competitiveness of alternative nuclear energy systems. The INPRO methodology on economics remains the main document on the subject, while this document further elaborates the methodology and is meant to be used as a supplementary guide for conducting the economic analyses and comparing alternatives nuclear energy systems to assess their sustainability ranking in terms of economic competitiveness. This publication also highlights the importance of system level effects – system reserves requirements, grid extension and strengthening requirements, frequency control requirements, etc., on the economics of different electricity generation technologies, which may altogether alter the economic ranking of the alternatives. In addition, this document also elaborates the environmental damages and external costs that influence the competitiveness of different electricity generation options. And finally, the document summarizes the macro-economic impacts of a nuclear power project for the national economy a country. The application of the economic concepts is illustrated in an annexure for a comparison of competitiveness of SMRs and large nuclear plants. The aim of this publication is to help Member States build capacity at the national level and support the technical experts in conducting sustainability assessments of alternative nuclear energy systems. This document can be used as a part of the INPRO service ASENES - Analysis support for enhanced nuclear energy Sustainability.

1.4. STRUCTURE

Section 2 describes the basic economic concepts needed for constructing suitable metrics for economic comparison of alternatives. The concepts are explained with generic examples. Section 3 presents some metrics generally used for economic comparison of alternative projects together with the calculation methods. These two sections provide foundation for conducting economic evaluation of alternative nuclear energy systems.

Section 4 presents the cost structure of a nuclear power plant, explaining the types of costs/expenditures involved at various stages of a nuclear power project, starting from the preparatory and project planning stage to construction of plant, operation of plant, decommissioning of plant, i.e., covering the entire life cycle of a nuclear power plant.

Section 5 explains the system effects for an electricity generation plant. It highlights the limitation of economic comparison of alternatives based on plant level analysis and describes additional costs imposed on the power system by a plant. It is pointed out that such cost may considerably influence the competitiveness of an electricity generation option.

Section 6 presents the environmental impacts and external costs of different electricity generation options. It is argued that the environmental damage costs and other external costs need to be taken into account for comparing alternatives for electricity supply.

Section 7 describes macroeconomic impacts of nuclear power project for a country. It explains, depending upon the status of an economy, how a nuclear power project may have a positive influence on the national economy or may cause significant burden. This analysis is useful to evaluate whether or not a country can afford to introduce (or expand) nuclear power in the country.

Section 8 explains the application limits for the models and tools presented in this publication, and Section 9 provides the concluding remarks.

Annex I to this publication provides an overview of the INPRO methodology in the area of Economics.

Annex II, titled Economic competitiveness of SMR, is included to demonstrate the application of the methodology for analyzing the economic competitiveness of a set of SMRs versus a large NPP.

Annex III, which is available as a supplementary electronic only file, describes the INRPO tool NEST for economic evaluation of nuclear energy systems, its data needs and results, together with its features for analyzing uncertainties in technical and economic parameters used as inputs. An example is also included in this section to illustrate its application.

2. BASIC ECONOMIC CONCEPTS FOR COMPARISON OF ALTERNATIVE PROJECTS

For a realistic economic comparison of alternative projects, familiarity with the principles, concepts and evaluation techniques is required. This section presents some basic economic concepts that are central to making economic comparison of alternative.

2.1. TIME VALUE OF MONEY

Let's assume, we want to buy a new car and visit a car dealer. He shows different cars and we short list two – Car A and Car B. Both are of same size, similar in appearance and have same features, but have different price. Car A has a price tag of US $ 20 000., while Car B costs US $ 19 000.

From the price viewpoint, the comparison is straight forward. Car B is cheaper compared to Car A. If we made our choice purely based on cost, our decision would be Car B. In this case, a direct comparison is possible, but there could be several situations when a direct comparison is not possible.

For, example, if we ask the car dealer, what financing options are available for the two cars. The car dealer informs that Car A is offered with zero down payment and 5-year monthly payments of US $ 450., whereas Car B is available at US $ 3000.- down payment and 5-year monthly equal payments of US $ 400.

If we add the total payments over the 5-year period, the sum is equal in both the cases:

- For Car A: US $ 450 · 12 · 5 = US $ 27 000;
- For Car B: US $ 3000 + US $ 400 · 12 · 5 = US $ 27 000.

The total payments for both the Cars are equal but this direct comparison is not realistic. First, we have to pay US $ 3000.- as the down payment in the Case of Car B, but no down payment for Car A, and second, the monthly payments in the two cases are different. These differences in payments schedule or cash flow are important for comparison of the two options. The main reason being that the US $ 3000. down payment for Car B, could be invested to earn some return. If we assume a 5% annual profit can be earned and include it in the cost comparison, then the two cash flows would not add to the same sum. The profit that could have been earned is called opportunity cost of capital.

Furthermore, the purchasing power of US $ 100 today is different from that of US $ 100 one year later, because of inflation or deflation. This difference in worth of a monetary amount at different point in time makes a direct comparison unrealistic.

In order to resolve these issues regarding comparison of alternatives with different streams of cash flow, the economists have developed the concept of "Time Value of Money". The concept is based on the premise that a rational investor would choose an option from which he/she could receive money today rather than the same amount of money in the future. As such, the notion is that "the money available at present time is worth more (or less in the case of deflation) than the identical sum in the future"[1]. If " i " is the interest rate that can be earned per year, then the worth of an amount of money available today will grow to Eq.(1):

$$F_1 = P \cdot (1 + i) \quad (1)$$

after one year, and to Eq. (2)

$$F_2 = P \cdot (1 + i)^2 \quad (2)$$

after two years, and so on.

Growth of an amount of money over time is presented in Figure 1.

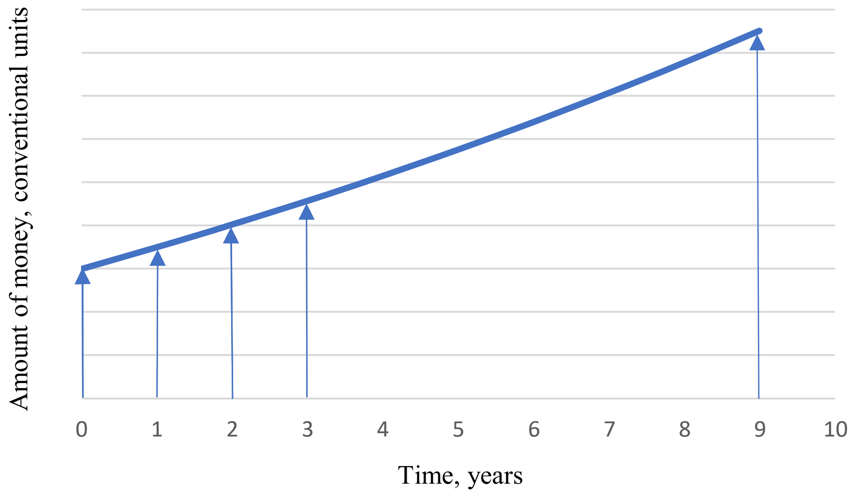

FIG. 1. Growth of an amount of money over time.

The relationship between the worth of an amount of money today with the worth in future can be generalized as Eq. (3):

$$F_t = P \cdot (1 + i)^t \quad (3)$$

where P is the worth of an amount of money at present, F_t is the worth of the amount of money in future at time t, *i* is the interest rate that can be earned per period.

If we are promised to receive an amount of money in future, we can calculate the worth of that amount at present time by the same formula Eq. (4) by rearranging it as below:

$$P = F_t / (1 + i)^t \quad (4)$$

This is called the discounted present value/worth of the future money.

With this process, the worth of an amount of money can be moved forward or backward in time easily. Moving forward the money is called compounding and moving backward is called discounting. The rate used in the case of moving forward is called interest rate while for moving backward is called discount rate. More description of discount rate is given in Section 2.3.

Now let's return to our example of cars. We can convert all the payments in both cases to a common point in time using the relationships above with the assumption of a 5% discount rate.

TABLE 1. THE PAYMENT SCHEDULE FOR THE TWO CAR OPTIONS AND THE CORRESPONDING PRESENT WORTH

	Payment schedule		Present worth	
Months	Car A	Car B	Car A	Car B
0	0.00	3000.00	0.00	3000.00
1	450.00	400.00	448.13	398.34
2	450.00	400.00	446.27	396.69
3	450.00	400.00	444.42	395.04
4	450.00	400.00	442.58	393.40
5	450.00	400.00	440.74	391.77
6	450.00	400.00	438.91	390.14
7	450.00	400.00	437.09	388.53
8	450.00	400.00	435.28	386.91
9	450.00	400.00	433.47	385.31
…	…	…	…	…
…	…	…	…	…
…	…	…	…	…
55	450.00	400.00	358.01	318.23
56	450.00	400.00	356.52	316.91
57	450.00	400.00	355.04	315.59
58	450.00	400.00	353.57	314.28
59	450.00	400.00	352.10	312.98
60	450.00	400.00	350.64	311.68
Total	$27 000.00	$27 000.00	$23 845.82	$24 196.28

The payment schedule for the two car options is shown in Table 1. For Car A, there is no payment at the start, but we have to pay US $ 450 each month over the five-year period. On the other hand, for Car B, an amount of US $ 3000 has to be paid at the start and US $ 400 each month over the five-year period. The sum for both the cases is US $ 27 000. If we assume an interest rate of 5% per year can be earned by investing this money, then we can calculate the present worth of all the payments in each case using the discounting process at a discount rate of 5% per year. Here since the payments are monthly, the monthly rate of 5% divided by 12 months has to be used. The last two columns show the present worth of the two cash flows calculated by discounting. The totals of the present worth can now be compared as the money has been converted to the same point in time. The comparison shows that the Car A would be cheaper than Car B if we take the respective financing being offered.

The above example shows that if two alternatives have different cash flows, they cannot be compared directly by comparing the simple totals of the payments. For a realistic comparison of the two options, the respective cash flows need to be converted to a reference point in time by using the concept of time value of money.

This procedure is very useful for comparing alternative options for electricity generation. Different power plants have quite different streams of expenditures involved over their life. Some power plants are expensive to construct but cheaper to operate (e.g., hydro and nuclear), whereas others are cheaper to build but expensive to operate (e.g., fossil fueled power plants). Furthermore, some can be constructed in relatively shorter time while others require much long period for construction. For example, a wind or solar PV plant can be constructed within one to two years. Likewise, a combustion turbine power plant can be constructed in about 2 years.

On the other hand, a large hydro or nuclear power plant would require 5-8 years to construct. Not only that the quantum of construction and operation costs are very different for different power plants, but their operating lives are also very different. A nuclear power plant can operate for 40-60 years whereas a combustion turbine power plant would have an operation life of 30 years. All these differences in the payment schedule of various costs related to different power plants make their economic comparison of complex. The concept of time value of money helps make a realistic comparison of the alternatives.

2.2. INFLATION AND ESCALATION

In the above discussion, we used the terms "interest rate" and "discount rate". Both these terms are used interchangeable for the concept of time value of money. What is a suitable value of "interest rate" or "discount rate" is dependent on the country condition and the situation for economic analysis in a particular study. The central banks in different countries set the base interest rate/discount rate and change it from time to time. For example, the Federal Reserves in the US and the European Central Bank in Europe (for the Euro-zone countries) set the base interest rates for specific economic objectives. All these rates are, however, in nominal terms; meaning that the rates include the effect of inflation.

It would be useful, here, to describe "inflation" and "escalation". In most countries, the economies operate under a continuous rise in general level of prices. The quantum of increase is different from country to country and also varies from time to time. This causes fall in the purchasing power of money. With the same amount of money, we can buy more things today compared to those later, say one year from now. The rise in general level of prices is called "inflation". More specifically, it "is a quantitative measure of the rate at which the average price level of a basket of selected goods and services in an economy increases over a period of time"[1]. The inflation in an economy has significant effect on time value of money and thus on economic comparison of alternative options.

Likewise, escalation refers to rise in prices of specific goods or service. It includes the effect of general inflation as well as real increase in prices due to other reasons, such as supply-demand conditions, resource depletion, regulations, etc. The difference between escalation and inflation is that the escalation is the rise in prices of specific goods or service whereas inflation is the rise in prices of a basket of goods and/or services. The apparent escalation could be higher or lower than inflation. The real escalation is the increase in prices over and above general inflation.

The real escalation rate in price of a specific good could be negative, if the general inflation is higher than the apparent increase in the price of that good. This can be illustrated with the following example.

[1] https://www.investopedia.com/terms/i/inflation.asp

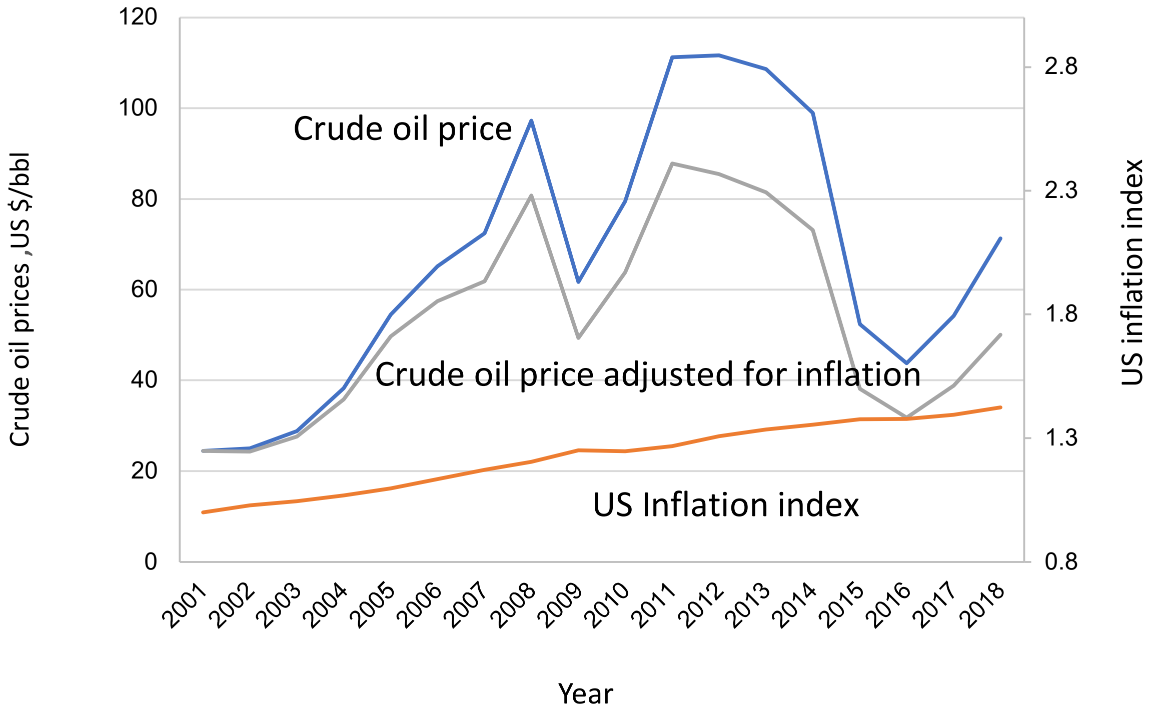

FIG. 2. Crude oil prices.

Figure 2, based on data from Ref. [2], shows yearly average price of crude oil from 2001 to 2018. Let's compare the changes in prices for two periods: 2001 to 2008 and 2011 to 2018. Here the change in yearly average prices between 2001 and 2008 is about 400% increase, whereas the change in price between 2011 and 2018 is a decrease of 35%. These are changes in the nominal prices of crude, i.e., the current dollar prices. This represents apparent escalation in the prices of crude oil. In the first 8-year period, there is a positive value for the apparent escalation whereas for the second 8-year period, the apparent escalation is negative (representing a decrease). The value of US dollar during these years has changed as well due to general inflation in the US economy. If the crude oil prices are adjusted with the US inflation index (shown in the figure), the real escalation in the crude oil prices would be different from the apparent escalation. For the period 2001 to 2008, it comes out as 330% increase in real term, equivalent to about 16% average annual real escalation rate. For the period 2011 to 2018, there is a 43% decrease in price of crude in real term, equivalent to -6.7% average annual real escalation rate.

The relation between the apparent and real escalation rates is as below Eq. (5):

$$(1 + e) = (1 + e_r) \cdot (1 + f) \qquad (5)$$

where e - apparent escalation rate, e_r - real escalation rate, f - inflation rate.

The escalation is very important for economic comparison of alternative electricity generation options. The reason being that the power plants usually take several years to construct during which the prices of construction materials, equipment and services may increase. And more importantly, since the operation lives of power plants are very long, during which the prices of fuels, like coal and gas, would change. If all these price changes are higher than the inflation rate, we would have a positive real escalation which needs to be reflected in the economic comparison of the alternatives.

2.3. DISCOUNT RATE

As mentioned in section 2.1, the process of converting future sum of money to a present date is called discounting and the rate used is called discount rate. Basically, discount rate is a representation of “time value of the money”. There are several appearances of discount rate. It depends on the context and situation what is meant by discount rate, and how is it used. In the banking industry, discount rate is the rate at which the central banks lend money to banks and other financial institutions. In the United Sates, it is called the “prime rate” and is set by the Federal Reserve. The banks use this rate as the base to determine the interest rate at which they lend money to each other or to their clients. This is also called discount rate.

The US Treasury Department issues, from time to time, T-Bills which usually have a face value of US $ 1000. The T-Bills are auctioned at a discount from the par value - meaning the purchase price is less than the face value of the bill. For example, if a T-Bill with a face value of US $ 1000 with one-year maturity is sold at a price US $ 950, this represents a 5% discount. This means that a buyer considers the worth of US $ 950 today equal to that of US $ 1000 a year from now. The 5% difference can be interpreted as the discount rate. Since the US T-Bills carry government’s guarantee, the discount rate can be considered risk free. It, however, includes inflation. If the inflation during the year is less than the discount on face-value (5%), the T-Bill buyer would earn a positive real interest rate. Conversely, if the inflation is higher than the discount, the buyer would lose despite being paid US $ 50 more than the invested amount.

In the case of business environment, the enterprises / companies make investment decisions among alternatives by comparing the expected cash flows from each alternative. The assessment however is made by comparing the total sum of discounted cash flows, as illustrated above in section 2.1. The discount rate, in such a case, is opportunity cost of capital– meaning what profit can be earned by investing the same amount elsewhere. This discount rate has to be higher or equal to the central bank’s risk-free rate, as it includes the business risk. It also includes inflation which reduces the real worth of cash flow.

For economic comparison of electricity generation options as well, the sum of discounted cash flows is compared. The discount rate, in this case, is generally the real discount rate and all cost (and benefits) in constant monetary term. The relation between nominal discount rate and real discount rate is given below Eq. (6):

$$(1 + r) = (1 + r') \times (1 + f) \tag{6}$$

where r – the nominal discount rate, r' - real discount rate, f - inflation rate.

2.4. ACCUMULATING A FUND BY UNIFORM ANNUAL PAYMENTS

If a fund is established to accumulate a certain amount of money over a given period by constant annual payments and the fund earns a compound interest, this arrangement is called Sinking fund. This arrangement is very practical for the situations like decommissioning of a nuclear power plant. As the decommissioning of a nuclear power plant is an essential task to be done in a long-term future and would cost a substantial amount of money, establishing a decommissioning fund based on the approach of sinking fund is suitable. A general practice is that during the operation of the nuclear power plant a certain amount of is allocated to the decommissioning fund which accumulates to an amount equivalent to the estimated cost of decommissioning. Annual payments to this fund can be calculated by using the sinking fund formula, as shown below.

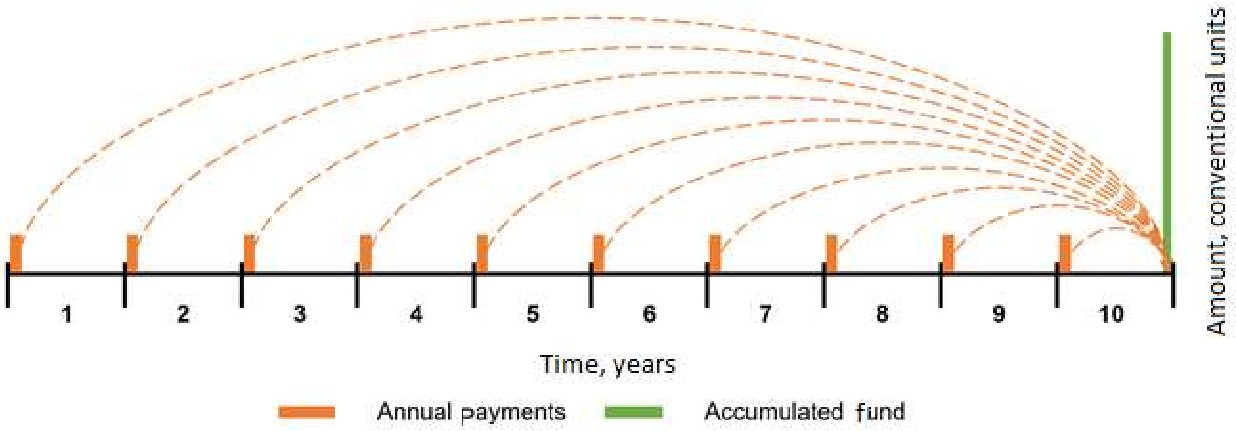

FIG. 3. Accumulating an amount in future by constant annual payments.

Let's assume we want to accumulate an amount "*F*" in ten years by depositing an amount "*A*" every year in a saving bank which offers "*i*" interest rate per year ($i \neq 0$). The first year's deposit will remain in the saving account for 10 years, the 2nd year deposit for 9 years and so on. The scheme of accumulating an amount in future by constant annual payment is presented in Fig. 3. We can compute the total accumulated amount *F* as Eqs. (7), (8):

$$F = A(1+i)^{10} + A(1+i)^{9} + A(1+i)^{8} + A(1+i)^{7} + A(1+i)^{6} + A(1+i)^{5} + A(1+i)^{4} + A(1+i)^{3} + A(1+i)^{2} + A(1+i)^{1} \quad (7)$$

$$F = A(1+i)[(1+i)^{9} + (1+i)^{8} + (1+i)^{7} + (1+i)^{6} + (1+i)^{5} + (1+i)^{4} + (1+i)^{3} + (1+i)^{2} + (1+i)^{1} + 1] \quad (8)$$

The sum of geometric series can be written as Eq. (9):

$$F = A(1+i)\frac{[(1+i)^{10} - 1]}{i} \quad (9)$$

If the payments are made at the end of each year, then the interest accumulation is for 9 years for the first year's payment, for 8 years for the 2nd year's payment and so on. In this case, the future amount accumulated by end-of-year payments will be Eq. (10):

$$F = A\frac{[(1+i)^{10} - 1]}{i} \quad (10)$$

This can be generalized as Eq. (11):

$$F = A\frac{[(1+i)^n - 1]}{i} \tag{11}$$

or Eq. (12)

$$A = F\frac{i}{[(1+i)^n - 1]} \tag{12}$$

This is called Sinking Fund Formula, assuming end of year payments (where $i \neq 0$).
For $i = 0$, $F = n \cdot A$, or $A = F / n$.

2.5. RECOVERING INVESTMENT BY UNIFORM ANNUAL PAYMENTS

Let's assume that we borrow US $ 100 000 for a project at an annual interest rate of 8%. The borrowed amount, together with the interest, has to be paid back in equal annual payments over a period of 10 years, as shown in Fig. 4.

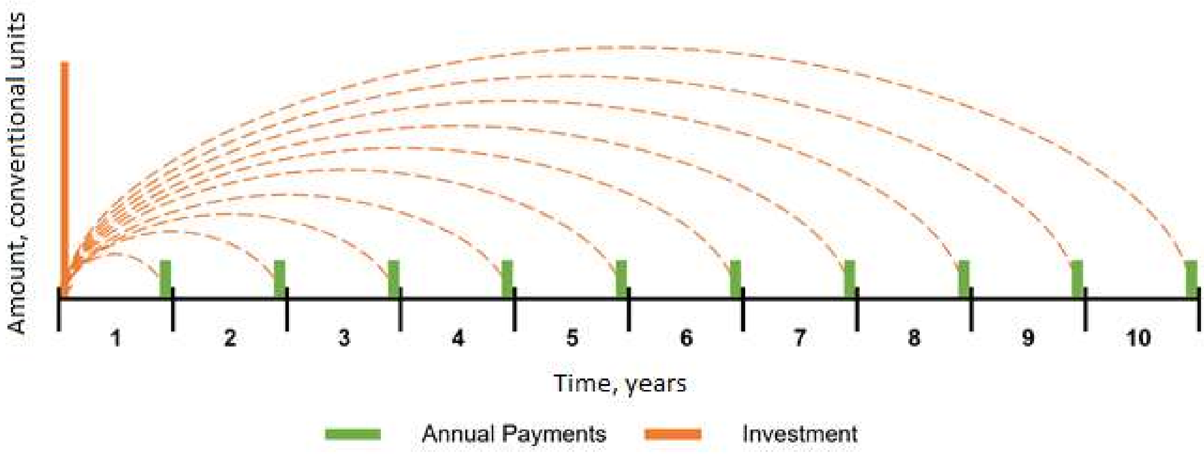

FIG. 4. Recovery of investment by uniform annual payments.

What amount we have to pay annually can be calculated as below:

If the 10 yearly payments are represented by

$$A_1, A_2, A_3, A_4, A_5, A_6, A_7, A_8, A_9, A_{10}$$

since these payments will be made in the future, we have to convert them to their present worth equivalent of the total is:

$$\frac{A_1}{(1+r)^1} + \frac{A_2}{(1+r)^2} + \frac{A_3}{(1+r)^3} + \frac{A_4}{(1+r)^4} + \frac{A_5}{(1+r)^5} + \frac{A_6}{(1+r)^6} + \frac{A_7}{(1+r)^7} + \frac{A_8}{(1+r)^8} + \frac{A_9}{(1+r)^9} + \frac{A_{10}}{(1+r)^{10}} \tag{13}$$

As the yearly payments would be equal, we have:

$$\frac{A}{(1+r)^1}+\frac{A}{(1+r)^2}+\frac{A}{(1+r)^3}+\frac{A}{(1+r)^4}+\frac{A}{(1+r)^5}+\frac{A}{(1+r)^6}+\frac{A}{(1+r)^7}+\frac{A}{(1+r)^8}+\frac{A}{(1+r)^9}+\frac{A}{(1+r)^{10}} \tag{14}$$

This sum needs to be equal to the amount borrowed, i.e., Eqs. (15), (16):

$$100\,000=\frac{A}{(1.08)^1}+\frac{A}{(1.08)^2}+\frac{A}{(1.08)^3}+\frac{A}{(1.08)^4}+\frac{A}{(1.08)^5}+\frac{A}{(1.08)^6}+\frac{A}{(1.08)^7}+\frac{A}{(1.08)^8}+\frac{A}{(1.08)^9}+\frac{A}{(1.08)^{10}} \tag{15}$$

$$100\,000=\frac{A}{(1.08)}\left[1+\frac{1}{(1.08)^1}+\frac{1}{(1.08)^2}+\frac{1}{(1.08)^3}+\frac{1}{(1.08)^4}+\frac{1}{(1.08)^5}+\frac{1}{(1.08)^6}+\frac{1}{(1.08)^7}+\frac{1}{(1.08)^8}+\frac{1}{(1.08)^9}\right] \tag{16}$$

On summing the geometric series of right-hand-side, we get Eq. (17):

$$100{,}000=\frac{A\,[(1.08)^{10}-1]}{[0.08\times(1.08)^{10}]} \tag{17}$$

And after rearranging Eqs. (18), (19):

$$A=\frac{[100\,000\times 0.08\times(1.08)^{10}]}{(1.08)^{10}-1} \tag{18}$$

$$A = 14{,}902.95 \tag{19}$$

This means, ten yearly payments of US \$ 14902.95 each will cover the borrowed amount and the interest.

The formula Eq. (20) can be generalized for recovering an investment "*Inv*" in a project with a desired profit at a rate "*r*" through annual uniform payments in "*n*" years, (where $i \neq 0$).

$$A=\frac{[Inv\cdot r(1+r)^n]}{(1+r)^n-1} \tag{20}$$

The ratio $\frac{A}{Inv}$ can be calculated which is referred as Capital Recovery Factor (CRF) Eq. (21):

$$CFR=\frac{[r(1+r)^n]}{(1+r)^n-1} \tag{21}$$

This is applicable for ($r \neq 0$). In cases $r = 0$, CRF = $1/n$.

This formula provides a convenient way of calculating annual charge for recovering investment cost of an electricity generation project. Let's consider a coal power plant with the data below (Table 2):

TABLE 2. BASIC DATA FOR A COAL POWER PLANT

	Coal power plant
Plant capacity	500 MW
Plant life	30 years
Average load factor	80%
Capital cost for completing the project	US $ 1.0 billion
Interest / Discount rate	8%

One can calculate the annual electricity generation for this plant as Eqs. (22) – (24):

$$\textit{Generation} = \textit{Plant capacity} \cdot \textit{Average load Factor} \cdot \frac{8\ 760}{1\ 000} (\text{in GW} \cdot \text{h})$$

$$= 500 \cdot \frac{80}{100} \cdot 8.76 \quad \text{GW} \cdot \text{h} \quad = \quad 3\ 504\ \text{GW} \cdot \text{h per year} \tag{22}$$

$$\textit{Capital recovery factor} = \frac{[r\,(1+r)^n]}{(1+r)^n - 1} \tag{23}$$

$$CRF = \frac{[r\,(1+r)^n]}{(1+r)^n - 1} = \frac{[0.08 \cdot (1.08)^{30}]}{(1.08)^{30} - 1} = 0.088\ 827 \tag{24}$$

The capital cost component of generation cost Eq. (25) can be calculated as:

$$\frac{\textit{Investment} \cdot \textit{Capital recover factor}}{\textit{Generation}} = \frac{\textit{US \$ 1.0 billion} \cdot \textit{0.088 827}}{3\ 504\ GW \cdot h}$$

$$= US\ \$\ 25.35\ per\ MW \cdot h \tag{25}$$

It could be noted that the capital cost used here is assumed to be the total capital cost on completion of the project, including the "Interest During Construction".

2.6. INTEREST DURING CONSTRUCTION

Most power plants take several years to construct. The cost of construction is spread over these years. If the investment funds for construction are borrowed, then the interest on the borrowed money has to be paid. Even if a part or the entire amount of the investment funds is provided by the project sponsors, utility or the government, the funds could have been invested elsewhere and a profit could have been earned. As such, the interest on the funds invested for the construction of plant need to be accounted for as a component of the cost of construction of plant. This is called "Interest During Construction" (IDC). To calculate the IDC, one needs to have information about:

- Construction cost – direct cost of materials, equipment, supplies, etc.;
- Duration of construction;

– Distribution of the construction cost over the construction period;
– Interest rate.

To illustrate, let's assume the coal power plant, in the above example, takes 4 years to construct and the construction cost is evenly distributed over the construction period. If the construction cost is US $ 822 million, the IDC would be as shown in Table 3 and Fig. 5.

TABLE 3. AN ILLUSTRATION OF IDC CALCULATION

	Construction cost (million US $)	IDC (million US $)
1	205.5	$205.5 \times [(1.08)^4 - 1] = 74.08$
2	205.5	$205.5 \times [(1.08)^3 - 1] = 53.37$
3	205.5	$205.5 \times [(1.08)^2 - 1] = 34.20$
4	205.5	$205.5 \times [(1.08)^1 - 1] = 16.44$
Total	822.0	178.09

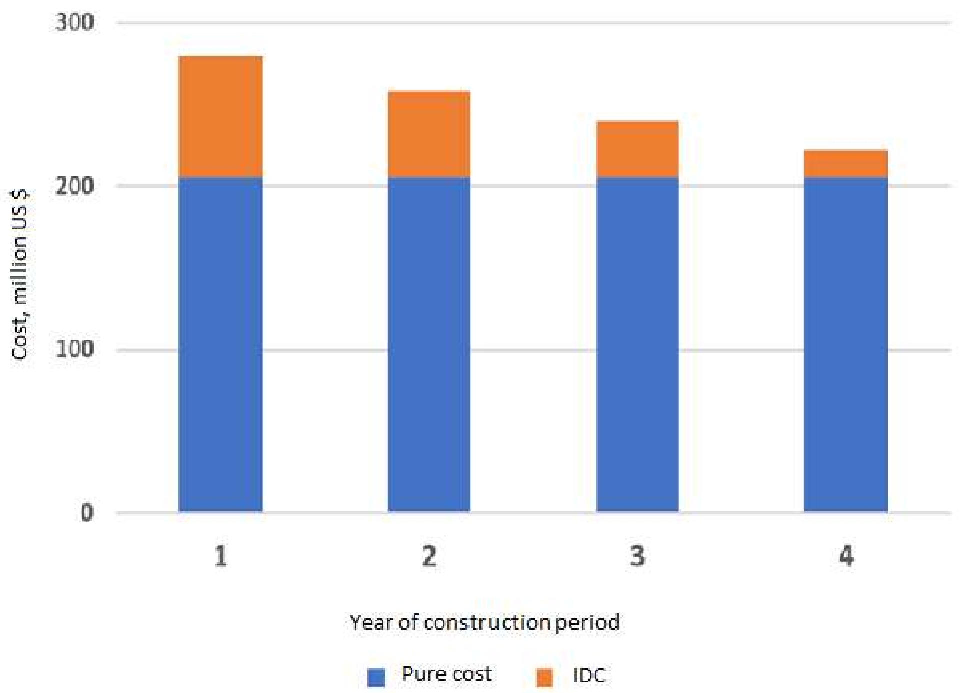

FIG. 5. Construction cost and IDC for each year of construction period.

Here it is assumed that the yearly investments are committed at the beginning of each year. As such, the IDC on 1st year's investment is due for 4-year period and IDC on 2nd year's investment is due for 3-year period and so on. The total IDC will be US $ 178.09 million. Consequently, the total capital cost on completion of the plant will be US $ 1.09 billion. It can be noted that the longer the construction period of a plant, the larger the IDC will be.

The IDC formula can be generalized as below Eq. (26):

$$\mathrm{IDC}=Inv\cdot\left[\sum_{t=1}^{t=T}\left\{f_t(1+i)^{T+1-t}\right\}-1\right] \tag{26}$$

where IDC - Interest during construction; *Inv* - Direct investment or Construction cost; f_t - fraction of Inv spent in year *t; T* - construction period (in integer); *i* - interest rate; *t* - construction years.

The variation of interest during construction as percentage of construction cost with different interest rates and construction periods is shown in Table 4.

TABLE 4. INTEREST DURING CONSTRUCTION AS PERCENTAGE OF CONSTRUCTION COST*

	Interest rate			
Construction period (years)	3 %	5 %	7 %	10 %
1	3.00 %	5.00 %	7.00 %	10.00 %
2	4.55 %	7.62 %	10.75 %	15.50 %
3	6.12 %	10.34 %	14.66 %	21.37 %
4	7.73 %	13.14 %	18.77 %	27.63 %
5	9.37 %	16.04 %	23.07 %	34.31 %
6	11.04 %	19.03 %	27.57 %	41.45 %
7	12.75 %	22.13 %	32.28 %	49.08 %
8	14.49 %	25.33 %	37.22 %	57.24 %
9	16.27 %	28.64 %	42.40 %	65.97 %
10	18.08 %	32.07 %	47.84 %	75.31 %
11	19.93 %	35.61 %	53.53 %	85.31 %
12	21.81 %	39.27 %	59.51 %	96.02 %

* Assuming uniform distribution of cost over construction years and funds committed at beginning of each year.

2.7. DEPRECIATION

All plants and machinery, including power plants, decrease in worth over time due to wear and tear. This decrease in worth of such assets is called depreciation. It is “an accounting method of allocating the cost of a tangible or physical asset over its useful life”[2]. From cost accounting viewpoint, depreciation is defined as the charges that need to be recovered from the revenues to repay the capital investment. Although depreciation is more important for financial analysis, it is also very useful for economic evaluation of electricity generation options because it represents how much of an asset's value has been used up at a certain point in time. For example, let’s assume a company buys computers for US $ 100 000 which are expected to have a 5-year useful life. This can be considered as company’s asset worth US $ 100 000 at the start. After one year, the value of this asset would be US $ 80 000 because one-fifth of its value is considered as used up. Likewise, the asset value after two years would be US $ 60 000, after three years US $ 40 000 and after four years US $ 20 000. And finally, after five years the asset value would be zero. The value of asset is decreasing (depreciating) each year by US $ 20 000 which is computed by dividing the asset value at the start by its useful life (this is the linear depreciation).

[2] https://www.investopedia.com/terms/d/depreciation.asp

There are several methods for calculating depreciation. The difference among the various methods for calculating depreciation is the quantum of reduction in value of an asset in different years. Some methods represent faster depreciation in the initial years whereas others represent slower. The total value of the asset, however, is depreciated completely over its useful life in all the methods. If at the end of the useful life of a plant, the used machinery and equipment can be sold as scrap, the price received is called ***Salvage value***. In such cases, depreciation is applied to the initial value of the asset minus its salvage value at the end of life. This net amount is called the depreciable value of the asset.

Accounting for depreciation is more relevant for financial analysis, and the choice of depreciation method has impact on tax computation. The tax laws and regulations in different countries allow a certain method as the applicable method for computing depreciation. The commonly used methods are:

(i) Straight-line method;
(ii) Declining balance method;
(iii) Sum-of-the-years digits method;
(iv) Sinking fund method.

A brief description of these methods is given below.
Straight-line method: This is the most commonly used method. In this case, the deprecation is constant in each year of the useful life, i.e., the value of an asset decreases linearly in a straight-line. The yearly depreciation amount can be calculated as Eq. (27):

$$D_t = \frac{Inv}{n} \tag{27}$$

where D_t - depreciation amount in year t; *Inv* - Investment for creating an asset; *n* - useful life of the asset.

We can also calculate the net asset value at any year as Eq. (28):

$$Net\ Asset\ Value\ at\ year\ t = (Inv - D_t) = Inv - t\frac{Inv}{n} \tag{28}$$

If at the end of useful life, the asset has some salvage value, then the above formulas can be modified as Eqs. (29), (30):

$$D_t = \frac{Inv - S}{n} \tag{29}$$

$$Net\ asset\ value\ at\ year\ t = Inv - t \cdot \frac{Inv - S}{n} \tag{30}$$

where *S* - salvage value of the asset at the end of its life.

Declining balance method: This method allows accelerated depreciation of an asset. In this case, the value of an asset decreases faster in the initial years and correspondingly slower in the later years. A constant rate of depreciation is applied to the remaining value of the asset at each year. The amount of depreciation deceases in each successive year as the depreciation rate is applied to the net asset value in that year.

For first year Eq. (31):

$$D_1 = r \cdot Inv \tag{31}$$

For $t = 2, 3, \ldots$ Eq. (32):

$$D_t = r\left(Inv - \sum_{i=1}^{t-1} D_i \right) \tag{32}$$

where D_t - depreciation amount in year t; Inv - Investment for creating an asset; $\sum_{i=1}^{t-1} D_i$ - accumulated depreciation amount up to year t -1; r - depreciation rate.

Since the depreciation rate is constant, the depreciation amount is higher in the initial years but gradually declines as the remaining balance of the asset value decreases. This accelerated method allows companies to reduce the tax burden in the initial years of the project.

Sum-of-the-years digits method: This is another method for accelerated depreciation. It offers larger depreciation in the early years. It is calculated by taking the ratio between the remaining years of asset life and the sum of digits of all years and multiplying this ratio by the depreciable value of the asset. For example, if an asset has a five-year life, the sum of the digits one through five would be 1+ 2 + 3 + 4 + 5 = 15. For the first year, since the remaining life is 5 years, the ratio will be 5/15; for the second year the remaining life is 4 years thus the ratio will be 4/15, and so on. Continuing this way, for the third year 3/15, for the fourth year 2/15, and for the last year (fifth year) the ratio will be 1/15. These respective ratios can be multiplied to the asset's depreciable value to arrive at the depreciation amount for each year. A generalized formula can be written as follows Eq. (33):

$$D_t = \left[2 \cdot \frac{n - t + 1}{n\ (n + 1)} \right] \cdot Inv \tag{33}$$

where D_t - depreciation amount in year t; Inv - Investment for creating an asset; n - useful life of the asset.

If the asset has a salvage value, S, at the end of its life, then Eq. (34):

$$D_t = \left[2 \cdot \frac{n - t + 1}{n\ (n + 1)} \right] \cdot (Inv - S) \tag{34}$$

Sinking fund method: This is equivalent to establishing a fund with constant annual deposits throughout the life of a project (an asset). The fund is assumed to earn an interest and grow to accumulate an amount equal to the initial value of the asset or initial value minus salvage value of the asset, if there is some salvage value. The yearly depreciation amount is equal to the constant annual deposits plus the interest on the accumulated fund. Since, the accumulation in the fund is small in the early years, and consequently the interest on it is also small, the depreciation amount is lower initially and increases with time over the life of the asset. This pattern is opposite to the depreciation pattern in other methods, e.g., the declining balance method or the sum-of-the-years digits method. A generalized formula can be written as follows Eq. (35):

$$D_t = \left[r \cdot \frac{(1 + r)^{t-1}}{((1 + r)^n - 1)} \right] \cdot Inv \tag{35}$$

where D_t - depreciation amount in year t; Inv - Investment for creating an asset; r - depreciation rate, ($r \neq 0$); n - useful life of the asset.

If there is some salvage value, S, of the asset at the end of its life, then Eq. (36):

$$D_t = \left[r \cdot \frac{(1 + r)^{t-1}}{((1 + r)^n - 1)} \right] \cdot (Inv - S) \tag{36}$$

A comparison of the four methods is given in Figure 6.

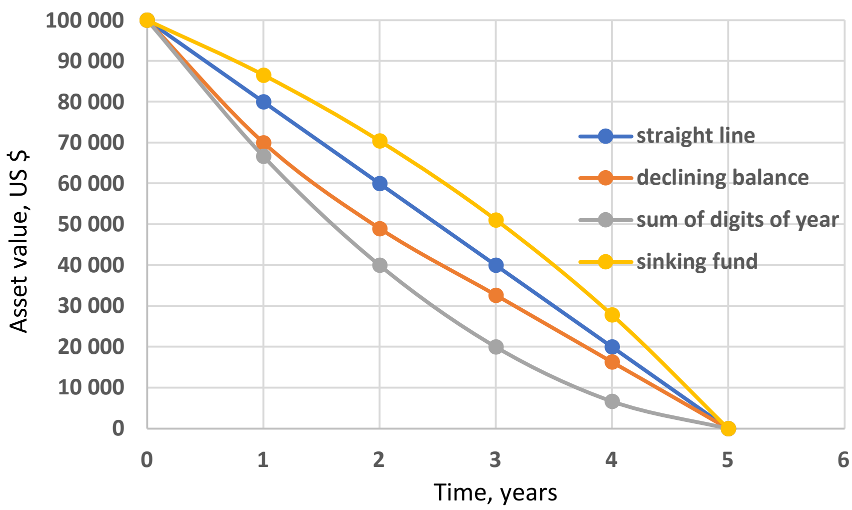

FIG. 6. Depreciation of an asset value over its life in different methods.

3. METRICS FOR ECONOMIC COMPARISON OF ALTERNATIVE PROJECTS

Based on the above economic concepts, several metrics have been designed for economic comparison of alternative projects, including power projects. This section describes the commonly used metrics.

3.1. MINIMUM PRESENT WORTH OF COSTS

If two or more alternative projects can produce same good or service with the same quantity and quality, we can rank the projects by comparing the present worth of their respective total costs/expenditure, including construction costs, operation costs and all other related costs, over their entire life cycle. The preference will be given to the project which has the minimum present worth of costs Eq. (37):

$$\text{Present worth of costs} = \sum_{t=1}^{t=n} \frac{C_t}{(1+r)^t} \tag{37}$$

where C_t - Cost in year t; r - discount rate; n - life cycle of the project.

It could be noted that the use of present worth of costs is applicable to the comparison of alternative projects that produce same good or service with the same quantity and quality.

3.2. MAXIMUM PRESENT WORTH OF NET PROFITS

The alternative projects can also be ranked by comparing the present worth of their net profits over their entire life cycle. The project which is expected to deliver maximum net profits Eq. (38) would be preferred.

$$\text{Present worth of net profits} = \sum_{t=1}^{t=n} \frac{R_t - C_t}{(1+r)^t} \tag{38}$$

where C_t - Cost in year t; R_t is Revenue in year t; r - discount rate; n - life cycle of the project.

Again, this criterion is applicable to the comparison of alternative projects that produce same good or service with the same quantity and quality, that can be sold at the same price. This criterion is also called net present worth or net present value (NPV). For computing this metric, the future revenues have to be estimated assuming future prices. If the projects are different in sizes, in some cases, scaling of the NPV would be possible.

3.3. MAXIMUM BENEFITS TO COST RATIO

The limitation on applicability of the above two criteria, i.e., the alternative projects produce same good or service with the same quantity and quality, can be overcome by taking the ratio of the present worth of revenues/benefits to the present worth of costs. In this case, the comparison will be made among the alternatives based on the discounted revenues or benefits per unit of the discounted costs, and the project with highest value of the ratio would be preferred. This means that the project is selected which delivers the largest revenues per dollar spent on the project.

$$Benefits\ to\ costs\ ratio = \frac{\sum_{t=1}^{t=n} \frac{R_t}{(1+r)^t}}{\sum_{t=1}^{t=n} \frac{C_t}{(1+r)^t}} \tag{39}$$

where C_t - Cost in year t; R_t is Revenue in year t; r - discount rate; n - life cycle of the project.

A comparison of alternatives based on the above metrics is, however, highly dependent on the value of discount rate used. This can be illustrated with an example of benefit to cost ratio. Let's assume we are considering two alternative projects for starting a business. The project A needs US \$10 000 as investment and can be established in one year. It would run for 5 years during which it needs US \$ 2000 per year as operating cost and will produce declining revenues as shown in Figure 7. The project B, on the other hand, requires two years to establish with the investments of US\$ 10 000 in the first year and US \$ 5000 in the 2nd year. It would run for 4 years and incur US \$ 500 per year as the operating cost and producing revenues of US \$ 6000 per year. The costs and revenues for the two projects are shown in Figure 7, (costs are shown as negative cash flow while the revenues as positive flow).

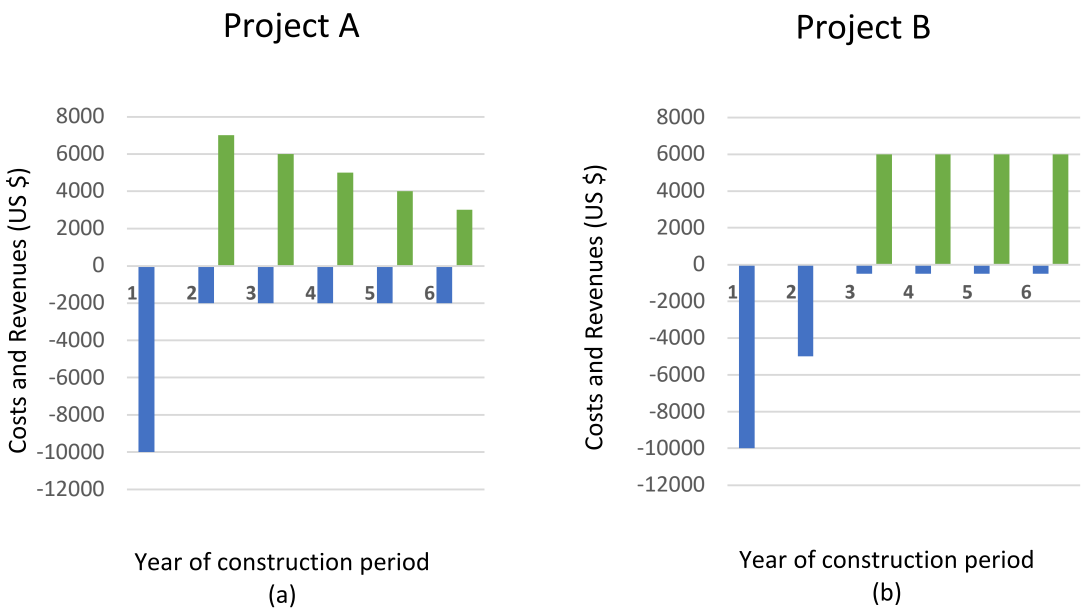

FIG. 7. An example of cash flow (expenditures and revenues) for two projects ((a) – Project A, (b) – Project B).

In this example, the two projects have very different cost structures and cash flows. They may also be different in their product. We can compute the Benefit to cost ratio of the sum of discounted revenues and the sum of discounted costs. If we assume 5% discount rate: We get

For Project A Eq. (40):

$$Benefits\ to\ costs\ ratio = \frac{\sum_{t=1}^{t=n} \frac{R_t}{(1+r)^t}}{\sum_{t=1}^{t=n} \frac{C_t}{(1+r)^t}} = \frac{21\,018.50}{17\,770.43} = 1.183 \tag{40}$$

And for Project B Eq. (41):

$$Benefits\ to\ costs\ ratio = \frac{\sum_{t=1}^{t=n} \frac{R_t}{(1+r)^t}}{\sum_{t=1}^{t=n} \frac{C_t}{(1+r)^t}} = \frac{19\,297.69}{15\,667.10} = 1.232 \tag{41}$$

In this case, the Project B is preferred as it has a higher Benefits to cost ratio.

If we use a discount rate of 10%, then the results will be reversed:

- For Project A Benefits to costs ratio = 1.119;
- For Project B Benefits to costs ratio = 1.082.

As such, the Benefits to cost ratio is a good criterion for comparing alternative projects but the comparison would be highly dependent on the value of discount rate used.

3.4. SHORTEST PAYBACK PERIOD

Payback period is the time needed to recoup the investment. It is also called break-even time. If the yearly net cash flow of a project is accumulated over time, the time when it becomes positive is the break-even point and the period between the start of operation and the break-even point is called payback period. Payback period Eq. (42) can be used to compare two alternative projects and the one with shorter payback period would be preferred.

$$Payback\ period: \sum_{t=1}^{t=t'} (R_t - C_t) = 0 \tag{42}$$

where C_t - Cost in year t (cash out-flow); R_t - Revenue in year t (cash in-flow); t' - time when the sum becomes zero.

If we consider the example of two projects presented in section 3.3 – Project A and Project B, the yearly net cash flow accumulated over time would be as shown in Figure 8. It can be noted that the accumulated net cash flow for Project A becomes positive earlier than Project B. There for the payback period for Project A is shorter than that of Project B, implying that the investment on Project A can be recovered in a shorter period compared to Project B. As such, the Project A is a preferred option based on payback period.

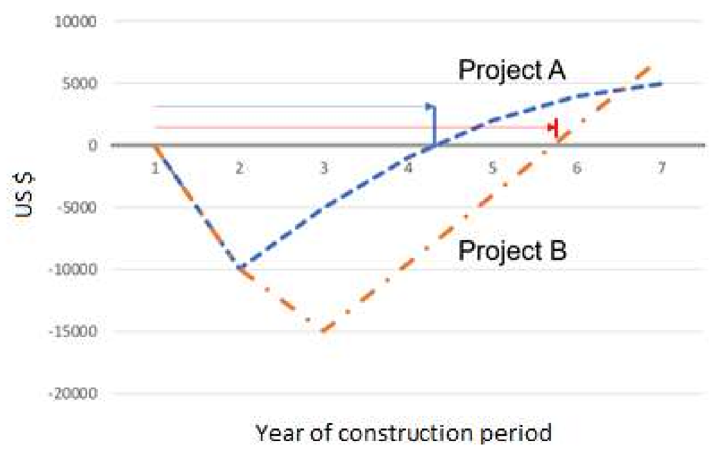

FIG. 8. Accumulated net cash flow for Project A and Project B.

Calculating payback period for comparing alternatives is a simple and easy method. There are, however, some limitations of this criterion. First, the time value of money is not accounted for in calculating payback period. Secondly, this criterion ignores the benefits occurring beyond the payback period. Thirdly, the schedule of costs and revenues is not reflected in calculating payback period. For example, if two projects are same in all aspects, (i.e., investments = US $ 100 000, net revenues = US $ 20 000 per year, construction time = 2 years), but have different schedule of costs during construction time, (one needs 70% of investment in 1st year of construction and 30% in 2nd year, and the other project needs 50% in each year), the payback period for both will be the same (i.e., 5 years). In view of these shortcomings, the payback period criterion needs to be used carefully for comparison of alternative projects.

3.5. MAXIMUM INTERNAL RATE OF RETURN

The above-mentioned difficulty of choosing an appropriate discount rate can be overcome by comparing the internal rate of return of the alternative projects. The Internal Rate of Return (IRR) is the rate used as discount rate at which the sum of discounted revenues and the sum of discounted costs are equal Eq. (43).

$$\sum_{t=1}^{t=n} \frac{R_t}{(1+r)^t} = \sum_{t=1}^{t=n} \frac{C_t}{(1+r)^t} \tag{43}$$

If revenues (R_t) and costs (C_t) for each year are known, one can calculate “r” from the above equation, which will represent the Internal rate of return (IRR). The project with highest IRR will be preferred.

A comparison based on IRR avoids the difficulty of selecting a suitable discount rate, but it suffers from other problems. For example, there could be multiple values for “r” satisfying the above equation. This could happen when the sign of the annual net cash changes from negative to positive more than once.

3.6. MINIMUM PER UNIT PRODUCTION COST

Most of the above-mentioned criteria assume same quantity being produced by each of the alternative projects. In real world hardly any two projects produce the same quantity; either the sizes/capacities are different or the annual utilization rates are different due to technical or natural reasons. Further, in many cases, the life cycle of the alternatives could be very different, for example a wind turbine compared to a nuclear power plant. The differences among the alternative projects in size, utilization rate or life, etc. make the applicability of above discussed criteria unsatisfactory. In such case, per unit production cost can be used as a suitable criterion for comparison of alternative projects.

For calculating the per unit production cost of a project, the following items have to be computed:

Annual charge Eq. (44) for recovering the total capital cost over the project's operational years: This can be calculated by using the Capital recovery factor described in section 2.5.

$$\begin{aligned} \textit{Annual capital charge} &= \textit{Total capital investment} \cdot \textit{Capital recovery factor} \\ &= \textit{Total capital investment} \cdot \frac{[r\,(1+r)^n\,]}{(1+r)^n - 1} \end{aligned} \tag{44}$$

where *Total Capital Investment* - total cost for completing the project, including IDC; r - discount rate ($r \neq 0$); n - operation life of the project.

Annual operation cost: This would include all costs related to running the plant including fuel cost.

Annual production. Assuming the annual production will be constant over the operation life.

$$\textit{Per unit production cost} = \frac{\textit{Annual capital charge} + \textit{Annual operation cost}}{\textit{Annual production}} \tag{45}$$

This method is embedded in INPRO tool NEST for economic evaluation of nuclear energy systems. This, however, assumes a constant yearly production and constant operation cost, including fuel cost. For comparison of alternatives, this method is quite satisfactory.
Another method for calculating the per unit production cost is based on the determination of the "Required rate" which recovers all the costs over the life of plant. Since the revenues and the costs have different streams in terms of temporal schedule, the present worth of the two streams can be equated to compute the "Required rate" Eqs. (46), (47). In this case, the yearly production and operation cost need not be constant.

$$\sum_{t=1}^{t=n} \frac{\mathrm{Rate} \cdot \mathrm{Prod}_t}{(1+r)^t} = \sum_{t=1}^{t=n} \frac{C_t}{(1+r)^t} \tag{46}$$

where $\mathrm{Rate} \cdot \mathrm{Prod}_t$ - revenue earned from the project in year t; Ct - cost / expenditure on the project in year t (all types of costs); r - discount rate; n is operation life of the project.

$$Rate = \frac{\sum_{t=1}^{t=n} \frac{C_t}{(1+r)^t}}{\sum_{t=1}^{t=n} \frac{Prod_t}{(1+r)^t}} \tag{47}$$

If the production from the plant is sold at this "Rate", all the costs of the project will be recovered. As such, this Rate represents the Per unit production cost Eq. (48).

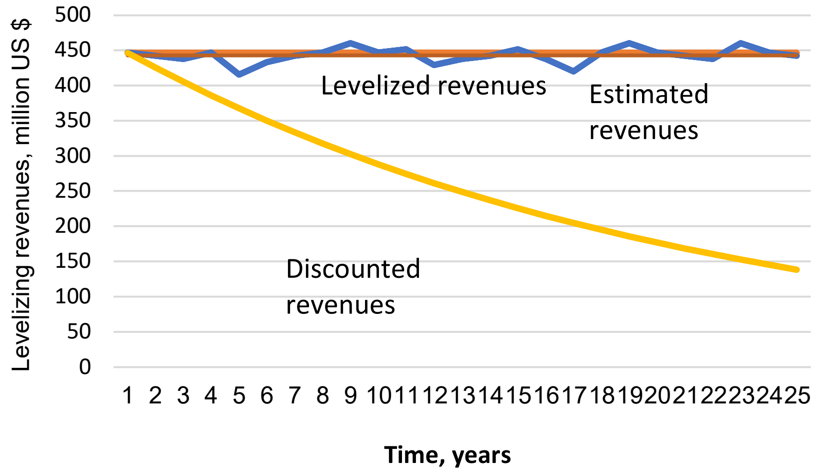

FIG. 9. Various representations of the revenues

$$Per\ Unit\ production\ cost = \frac{\sum_{t=1}^{t=n} \frac{C_t}{(1+r)^t}}{\sum_{t=1}^{t=n} \frac{\mathrm{Prod}_t}{(1+r)^t}} \tag{48}$$

Here Prod_t - production of the project in year t.

3.7. HIGHEST RETURN ON INVESTMENT

In the private business environment, another criterion often used by the investors for comparing alternative investment options is Return on investment (ROI). A return-on-investment measures "how much money or profit is made on an investment as a percentage of the cost of that investment"[3]. It shows the effectiveness and efficiency of an investment to generate profits. It can be calculated as follows Eq. (49):

$$Return\ on\ investment = \frac{Gain\ on\ investment - Cost\ of\ investment}{Cost\ of\ investment} \cdot 100 \tag{49}$$

For example, if 1000 shares of a company are bought at US $ 10 per share and after one year the shares are sold at US $ 11 per share, then

- Cost of investment = US $ 10 · 1000 = US $ 10 000
- Gain on investment = US $ 11 · 1000 = US $ 11 000

Then Eq. (50):

$$\begin{aligned} Return\ on\ investment &= \frac{Gain\ on\ investment - Cost\ of\ investment}{Cost\ of\ investment} \cdot 100 \\ &= \frac{US\ \$\ 11\,000 - US\ \$\ 10\,000}{US\ \$\ 10\,000} \cdot 100 = 10\% \end{aligned} \tag{50}$$

This value can be compared with ROI of an alternative. Clearly, the higher the ROI the better the investment option. Calculating ROI is simple and easy to interpret. Besides the estimates of

[3] https://www.investopedia.com/terms/r/returnoninvestment.asp

investment, assumptions on future prices/revenues and costs are needed. The comparison of alternatives based on ROI however suffers from some shortcomings: the lifetime (holding period) of investment is not considered and the time value of money is ignored.

A modified ROI can be calculated to account for the lifetime of investment. The overall ROI can be converted to annualized ROI by Eq. (51):

$$Annualiesed\ ROI = \left[\left(1 + \frac{ROI}{100}\right)^{\frac{1}{T}} - 1\right] \cdot 100 \tag{51}$$

where T is the lifetime (holding period) of investment.

4. COST OF ELECTRICITY GENERATION FROM A NUCLEAR POWER PLANT

Decisions on choosing among various electricity generation options require consideration of multiple factors. Most important among them are technical, economic, environmental and social aspects.

4.1. COUNTING THE COSTS

For economic comparison it is important that all the costs related to each of the projects are identified and estimated. The costs related to an electricity generation project can be grouped as:

- Costs for construction of a power plant;
- Costs for fueling the plant;
- Costs for operation and maintenance of the plant;
- Costs for replacement of major equipment during the life of the plant;
- Costs for dismantling / decommissioning of the plant after its operation life;
- Costs for environmental protection and waste management;
- Costs of external factors – externalities.

The cost accounting practices vary greatly from country to country. Different terminologies and definitions are used for categorization of various costs. In some cases, the national tax rules also determine categorization of costs. The IAEA has developed a cost accounting system for economic evaluation of bids for a nuclear power project [3]. This accounting system facilitates organizing all the costs related to a nuclear power project into various categories and ensuring their completeness. The IAEA's accounting system can be used, with some adjustments, for other type of power plants as well. It is crucial that for comparing different types of power plants their respective cost estimates are prepared using the same methodology. Consistency of various data and assumptions needs to be ensured for a realistic comparison.

For estimating the above costs for an electricity generation project, one needs more details for each of these cost categories. The next section briefly describes various costs related to an electricity generation project.

4.2. COST STRUCTURE OF A NUCLEAR POWER PROJECT

A nuclear power project, like any other project, involves different stages of development. Its life cycle extends up to 100 years – starting with project planning and preparation stage that may spread to 3 - 5 years, followed by construction stage which may take 6 - 10 years. The nuclear power plants have very long operation lives – 40 - 60 years. Even after end of operation, these plants need to be kept safe and secure for a long period before decommissioning and dismantling. Figure 10 shows the different stages of a nuclear power project during it entire life.

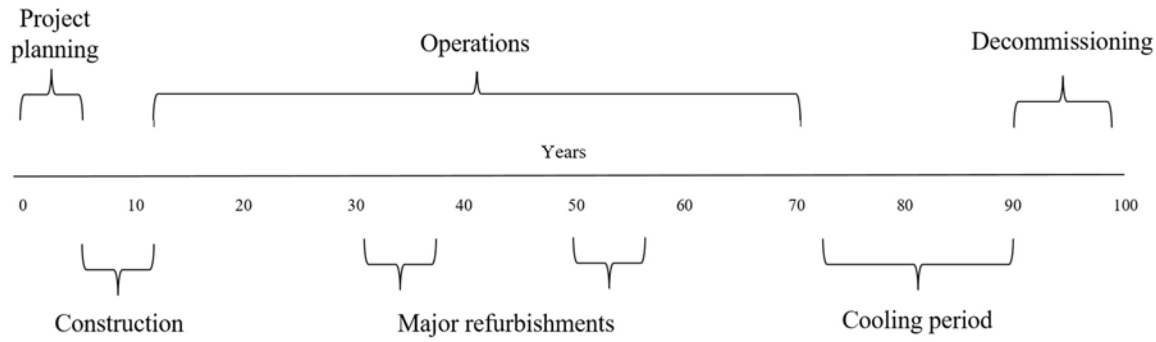

FIG. 10. Different stages of a nuclear power project.

During each of these stages, specific expenses are involved which determine the economics of the nuclear power project. Figure 11 presents a typical profile of expenditures at various stages of a nuclear power project. During the project planning stage, several preparatory tasks are performed, including feasibility studies, site investigation, preparation and evaluation of bids, etc. The cost for these tasks can be several tens of million US dollars. The next stage is actual construction. This is the most capital-intensive stage. The total cost (including IDC) can be around US $ 5000/kW of capacity. During the 40-60 years of operation, the annual expenditure on fuel and O&M is relatively small, about US $ 100/kW. However, during this stage, there could be some significant expenditure, a couple of 100 million dollars, on refurbishment and replacement of some major equipment[4]. After end of operation, depending upon decommissioning strategy, there could be a cooling period extending 15 - 20 years, during which some expenditure is incurred to keep the plant safe and secure. And finally, there is a significant expenditure for decommissioning and dismantling the plant in a range of US $ 300-1000 million.

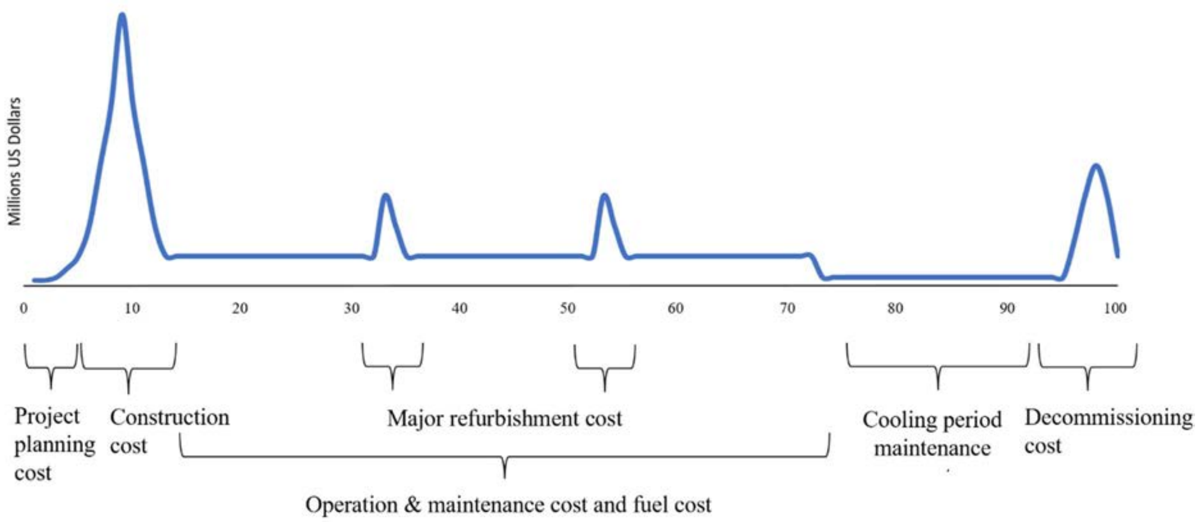

FIG. 11. Relative annual costs at various stages of a nuclear power project.

[4] https://www.iea.org/reports/projected-costs-of-generating-electricity-2020

4.3. TOTAL CAPITAL COST

The costs incurred for construction of a power plant include, project planning cost, engineering, procurement and construction cost, inventory cost (e.g., fuel and spare parts inventories), owner's cost, contingencies, escalation, interest during construction, etc. This is also called total capital cost.

TABLE 5. TYPICAL STRUCTURE OF CONSTRUCTION COST A NUCLEAR POWER PROJECT

Cost item	%
Equipment	
Nuclear steam supply system	12%
Electrical and generating equipment	12%
Mechanical equipment	16%
Instrumentation and control system (including software)	8%
Construction materials	12%
Labour onsite	25%
Project management services	10%
Other services	2%
First fuel load	3%
TOTAL	100%

Table 5 presents typical breakdown of the construction cost of a nuclear power plant[5]. Though each project is designed, built/manufactured, installed and commissioned according to the specific requirements/standards of a nuclear power plant, it can be noted that most of the equipment and services are of conventional nature. For example, turbine and generator equipment, auxiliary equipment, water intake and heat rejection, etc., are similar to a conventional power plant. The pure nuclear item is the nuclear steam supply system. Its cost is only about 12% of the total cost of a nuclear power plant. As such, the relatively high cost of a nuclear power plant is not for the nuclear island.

Figure 12, based on data from Ref. [4], presents estimates of the historical and under-construction nuclear power projects in different countries.

[5] https://www.world-nuclear.org/information-library/economic-aspects/economics-of-nuclear-power.aspx

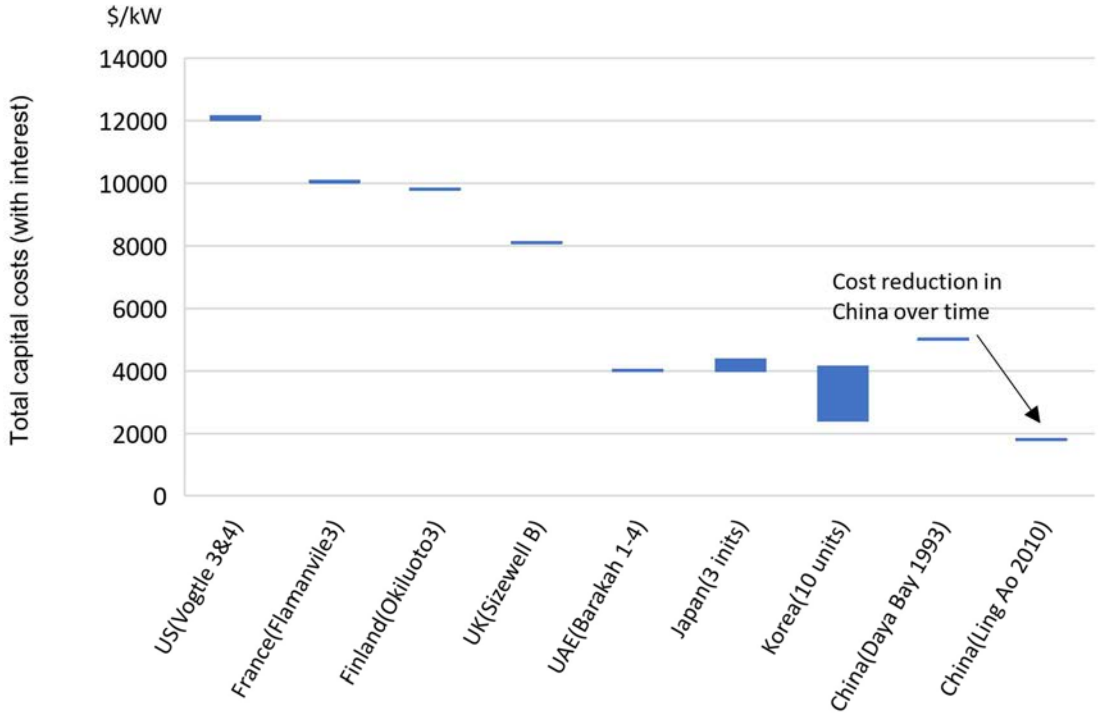

FIG. 12. Overnight construction cost of a nuclear power plant.

4.3.1. Overnight capital cost

If all the items in the above Table 4 are purchased at once, the total cost incurred will be the overnight capital cost, i.e., the cost if the plant is built over-a-night. The overnight capital cost includes pure construction cost, owner's cost, other costs and contingencies. These sub-categories are described in the following paragraphs. It may be noted that the overnight capital cost is not the actual expenditure on constructing a nuclear power plant because the prices of material, equipment and service may change during the construction period. Thereby increasing the total cost of construction. Furthermore, the funds spent on construction would carry an interest charge to cover the interest on the borrowed money or/and the return-on-investment funds.

4.3.1.1. Pure construction cost

The cost of materials, equipment and labour for designing, manufacturing, building, erecting and commissioning of a nuclear power plant is called the pure construction cost. It includes:

– Structures and site facilities;
– Reactor equipment;
– Electric plant equipment;
– Miscellaneous plant equipment;
– Water intake and heat rejection system;
– Ancillary construction facilities;
– Construction management, equipment and services;
– Home office engineering and services;
– Field office engineering and services.

A typical breakdown of pure construction cost in terms of equipment, materials and labour is given in Fig. 13, based on data from the World Nuclear Association (WNA) information library[6]. It can be noted that the on-site labour cost is the largest component of the pure construction cost, while the nuclear steam supply system is only 12%. A similar breakdown in terms of main activities is given in Table 6, also based on data from the WNA information library[4]

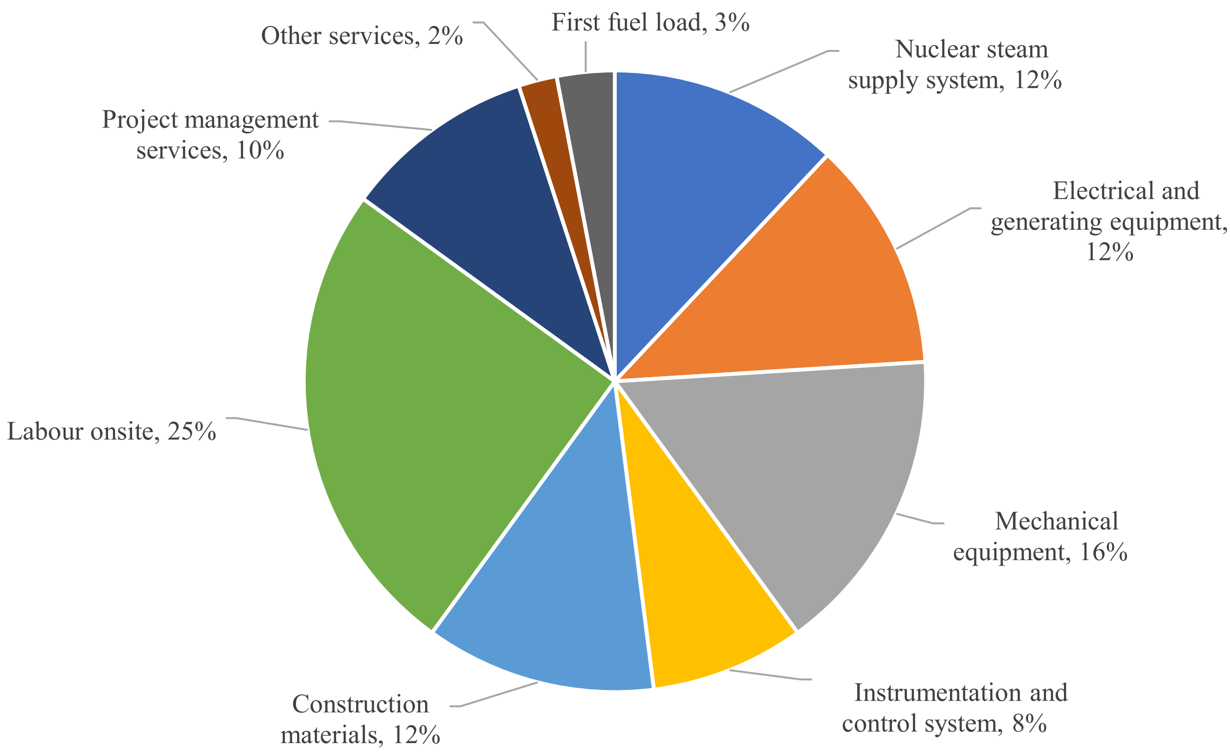

FIG. 13. Typical breakdown of construction cost for an LWR.

TABLE 6. TYPICAL BREAKDOWN OF CONSTRUCTION COST BY ACTIVITY FOR AN LWR.

Design, architecture, engineering and licensing	5%
Project engineering, procurement and construction management	7%
Construction and installation works:	
Nuclear island	28%
Conventional island	15%
Balance of plant	18%
Site development and civil works	20%
Transportation	2%
Commissioning and first fuel loading	5%
Total	100%

[6] https://www.world-nuclear.org/information-library/economic-aspects/economics-of-nuclear-power.aspx

4.3.1.2. Owner's costs and spare parts inventory

The owner’s costs include the cost of land, preparatory efforts, feasibility studies, etc. These are also intended to cover items such as administrative and oversight costs during construction, operators’ training, initial startup problems, and inventory of fuels and consumables. Some of these costs are site-specific and vary from country to country. Typically, the Owner's costs are US $ 200 to 300 million for a 1000 MW nuclear power plant.

4.3.1.3. Other costs

There are other costs that can be significant and are to be included in the total capital construction cost estimate, if not already covered by pure construction cost or owner’s cost. For example, temporary site facilities, project management, engineering services and field office. The cost for providing access to the site, e.g., roads, rail, ports, etc., need also be accounted for, if not already covered by other categories. These costs are often expressed as a percentage of the capital costs but are site specific and depend upon the existing infrastructure. In some cases, the existing infrastructure would need enhancement, e.g., strengthening bridges, for transportation of heavy equipment.

4.3.1.4. Contingencies

For all large-scale projects, adequate contingency costs are added to the project cost estimates. These are meant to cover (i) any additional costs that could arise from a more detailed design of a definitive project and (ii) uncertainty in the estimated costs. Contingencies cost are typically 10 - 15% of the capital cost of a nuclear power plant. Higher contingencies’ cost (may be 20%) is added in the case of a relatively new technology because of its unproven design. Such costs may decrease as experience with a new technology would accumulate.

4.3.2. Escalation during construction

The increase in prices of material, equipment, labour and services during the construction period is called escalation during construction. If this increase is expected to be higher than general inflation in the country, a positive real escalation has to be accounted for in estimating the cost of construction. The escalation rate can be assumed based on historical data. For example, Fig 14, based on data from Ref. [5], shows the trend in capital cost index for power plants. Over the period 2000 to 2016, the capital cost of power plants, excluding nuclear, increased 87% in North America and 77% in Europe. This implies that the average annual escalation rate for the capital cost of power plants in North America was 4%.

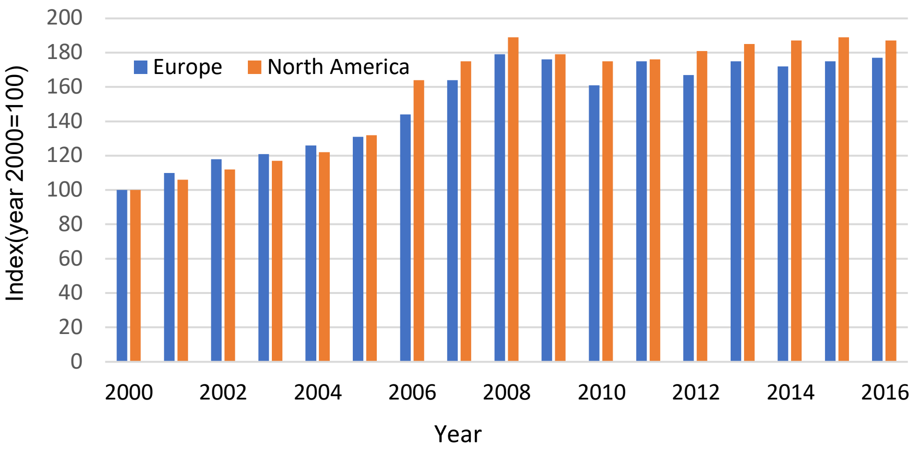

FIG. 14. Trend in power plant capital cost index (without nuclear).

The method for calculating escalation during construction can be illustrated with the example discussed in section 2.5. To recall the project details: it is expected to take 4 years for construction and the cost is evenly distributed over this period. The pure construction cost has been estimated as US $ 822.00 Million. If we assume, each year's cost is paid at the beginning, then a 4% escalation can be calculated as shown in Table 7.

TABLE 7. AN ILLUSTRATION OF CALCULATION OF ESCALATION DURING CONSTRUCTION.

	Pure construction cost (million US $)	Escalation (million US $)
1	205.5	$205.5 \cdot [(1.04)^0 - 1] = 0.00$
2	205.5	$205.5 \cdot [(1.04)^1 - 1] = 8.22$
3	205.5	$205.5 \cdot [(1.04)^2 - 1] = 16.77$
4	205.5	$205.5 \cdot [(1.04)^3 - 1] = 25.66$
Total	822.0	50.65

Usually, the yearly payments are not at the beginning of the year but spread over each of the construction years. To reflect this situation approximately, the escalation can be applied for half a year for the first year's cost, one and a-half year period for the second, and so on. In this case the calculation would be modified as below in Table 8.

TABLE 8. AN ILLUSTRATION OF CALCULATION OF ESCALATION DURING CONSTRUCTION.

	Pure construction cost (million US $)	Escalation (million US $)
1	205.5	$205.5 \times [(1.04)^{0.5} - 1] = 4.07$
2	205.5	$205.5 \times [(1.04)^{1.5} - 1] = 12.45$
3	205.5	$205.5 \times [(1.04)^{2.5} - 1] = 21.17$
4	205.5	$205.5 \times [(1.04)^{3.5} - 1] = 30.24$
Total	822.0	67.93

The second method is more commonly used. As such we generalized this method as the suitable method for calculation of escalation during construction.

The EDC formula can be generalized as below Eq. (52):

$$\text{Escalation during construction} = Inv\left[\sum_{t=1}^{t=T}\left\{f_t\left(1+e\right)^{(t-0.5)}\right\} - 1\right] \tag{52}$$

where *Inv* is the construction cost or overnight investment cost, f_t is the fraction of *Inv* spent in year *t*, *T* is the construction period (as an integer) and *e* is the escalation rate.
In practice, all bids and contracts for construction of a power plant include escalation clauses to account for price increase in material, equipment, etc. during the construction period.

4.3.3. Interest during construction

As described in Section 2.6, irrespective of the source of funds for construction of a power plant, the interest during construction needs to be included in the total cost of the plant. If the funds are borrowed, then the interest on borrowed money is a clear financing cost. If the funds are coming from investors, then the opportunity cost – the return from investing elsewhere, can be considered as the financing cost. If the construction cost is covered by a mix of borrowed funds and equity, a weighted average cost of capital can be used to calculate interest during construction.

For calculating the interest during construction, besides using a suitable interest rate, the timings for commitment of funds in each year is needed – i.e., the construction cost in each year is considered at the beginning of the respective year, or mid-year point. Although, the payments for the material, equipment, labour, services, etc., are spread over the years, the funds are to be available well ahead of the date of payment. As such, assuming the funds are committed at the beginning of each year is a realistic assumption.

Secondly, the interest during construction needs to be calculated on the escalated amount of the overnight construction cost, as illustrated in the Table 9 below for our example (assumed were a 4% escalation rate and a 5% per annum interest rate).

TABLE 9. AN ILLUSTRATION OF CALCULATION OF EDC AND IDC

	Overnight construction cost (million US $)	Escalation during construction (million US $)	Escalated construction cost (million US $)	Interest during construction (Million US $)
1	205.50	205.5 × [(1.04)$^{0.5}$ - 1] = 4.07	205.5 + 4.07 = 209.57	209.57 × [(1.05)^{4} - 1] = 50.80
2	205.50	205.5 × [(1.04)$^{1.5}$ - 1] = 12.45	205.5 +12.45= 217.95	217.95 × [(1.05)^{3} - 1] = 35.73
3	205.50	205.5 × [(1.04)$^{2.5}$ - 1] = 21.17	205.5 +21.17= 226.67	226.67 × [(1.05)^{2} - 1] = 22.34
4	205.50	205.5 × [(1.04)$^{3.5}$ - 1] = 30.24	205.5 +30.24= 235.74	235.74 × [(1.05)^{1} - 1] = 10.48
Total	822.00	67.93	889.93	119.35

These computations can be generalized as the formula below Eq. (53):

$$IDC = Inv'\left[\sum_{t=1}^{t=T}\left\{f_t\left(1+i\right)^{(T+1-t)}\right\} - 1\right] \tag{53}$$

where *Inv'* is the escalated pure construction cost or overnight investment cost, f_t is the fraction of *Inv'* (escalated *Inv*) in year *t*, *T* is the construction period (as an integer) and *i* is the interest rate.

4.4. OPERATION AND MAINTENANCE COST

Operation and maintenance (O&M) cost for a nuclear power plant is usually higher than that for other types of power plants due to some special characteristics of nuclear materials and stringent safety and security requirements. The main components of O&M cost for a nuclear power plant are:

(a) Wages and salaries for O&M staff, engineering and technical support staff, and administration staff;
(b) Consumable operating materials and equipment;
(c) Repair costs, including interim replacements;
(d) Insurance and taxes e.g., commercial nuclear liability insurance, government liability insurance, property insurance, replacement power insurance and taxes;
(e) Fees, inspections and review expenses;
(f) Radioactive waste management costs;
(g) Purchased services comprising the costs of outside services, such as: purchased energy for station needs, outside maintenance help;
(h) Research and development for specific applications, safety reviews, training of personnel, meteorological surveys, engineering studies, updating and reviews, in-service inspections, environmental studies, inspection of pressurized components;
(i) Interest charges on working capital;
(j) Decommissioning allowance.

It may be noted that some of these costs are independent of the capacity/load factor of the plant and have to be paid whether or not the plant is operated. For example, salaries of regular staff, insurance, decommissioning allowance, etc., and are represented as per unit of the capacity of the plant. Such costs are called fixed O&M costs. Other costs such as consumable materials and equipment, repair labour costs, etc., are proportional to the utilization level of the plant and are called variable O&M costs. These costs are reported as per unit of electricity generation.

4.5. FUEL COST

The nuclear fuel cycle has special technical characteristics which are dependent on the type of reactor technology. The light water reactors use enriched uranium fuel (or U-Pu mixed oxide fuel) whereas the heavy water reactors use natural uranium fuel. Likewise, other types of reactors, high temperature gas cool reactors, fast reactors, etc., all use different types of fuels. This section presents the description of fuel cycle cost for light water reactor and heavy water reactor technologies.

The nuclear fuel preparation processes for the two types of reactors are different and thus require different steps. The fuel cycle steps for light water reactors are:

- Purchase of yellowcake (natural U_3O_8);
- Conversion of U_3O_8 to UF_6;
- Enrichment to the appropriate level in ^{235}U (usually in the range of 3 - 5%);
- Fuel element fabrication;
- Shipping of fresh fuel to the nuclear reactor;
- Irradiation of the fuel loaded into the reactor;
- Storage of spent nuclear fuel;
- Shipping of spent nuclear fuel;

– Optionally, reprocessing of spent nuclear fuel for recovery of unused U and fissile Pu;
– Final disposal of radioactive wastes.

For calculation of fuel cost, first the estimates of quantities of nuclear material passing through various steps of fuel-cycle are required. The fueling of a light water reactor involves an initial core and regular reloads. Once the initial core of nuclear fuel is loaded into the reactor and commercial operation started, after about one year a portion of initial core, usually 1/3 to 1/4, is replaced by new fuel. When this process is repeated two or three times, an equilibrium is reached in which the quantity of nuclear material of each batch of reload is essentially the same. The quantities of nuclear fuel for the initial core and regular reloads are dependent on the technical aspects of the reactor and its expected utilization/operation. In this respect, the capacity of the reactor, enrichment levels of fuel assemblies, fuel burn-up, fuel residence time, etc., and the processes for fuel-cycle steps are the main determinants.

For heavy water reactor technology, the fuel cycle includes all the steps mentioned above except the enrichment. The quantities of nuclear materials however are different and are dependent on the technical characteristics of the reactor. Furthermore, the heavy water reactors do not need an initial core and the fuel loading is also on-line. The residence time for each fuel bundle is dependent on the technical aspects of the reactor and its average annual utilization/operation level.
Secondly, the estimates for costs/prices of nuclear material and fuel-cycle services are needed. These can be prepared by reviewing the historical trend in costs/prices of these items, the expected supply-demand conditions, technical developments, etc.

TABLE 10. LEAD AND LAG TIMES FOR NUCLEAR FUEL CYCLE STEPS FOR LWR AND HWR

	Lead time in months	LWR	HWR
Before loading fuel in reactor	Uranium purchase	24	17
	Conversion	18	13
	Enrichment	12	—
	Fuel fabrication	6	10
After discharging fuel from reactor	Transfer to interim storage	60	120
	Final disposal	480	120

Based on estimates for the quantities of nuclear materials and the costs/prices, the expenditure for all steps of the fuel cycle can be calculated. This is called “direct cost” for fuel. Since the various steps of fuel cycle occur at different points in time, the corresponding expenditure would have different timings. For example, the fuel fabrication step would occur about 6 months ahead of the time for its loading into a light water reactor. Similarly, the enrichment of uranium is to be done well ahead of the fuel fabrication step. After irradiation of fuel in the reactor, the fuel is discharged and kept underwater for cooling. The spent fuel is then transferred a storage facility, in the case of open fuel cycle, after about 60 months and finally disposed after 240 months. The lead and lag times for light water reactors and heavy water reactors are listed in Table 10, based on data from Ref. [6]. The timings of the expenditures for different fuel-cycle steps raises additional cost due to time value of money. This is called indirect cost and reflects interest charges or carrying charges on fuel.

4.6. DECOMMISSIONING COST

At the end of operating life of a nuclear power plant, it has to be decommissioned and dismantled. Depending upon the national regulation, the site has to be returned to a "green-field condition" or to a condition fit for similar or other purposes use. The cost estimates for decommissioning and dismantling tasks range from several hundred million US dollars to over a billion US dollars. As this cost will occur after the end of the useful life of the plant, the timings of this expenditure depend on the strategy adopted for decommissioning. Following are the main strategies being adopted by countries facing decommissioning of nuclear power plants.

(i) Mothballing: At the end of operating life, the plant is put into a state of protective storage. The spent nuclear fuel and radioactive wastes are removed from the site but the plant itself is left intact. Continuous radiation monitoring and environmental surveillance are arranged, and appropriate security procedures are established. The final dismantling is postponed for a long time period.

(ii) Entombment: In this approach, all the highly radioactive and contaminated components are sealed within a structure integral to the primary biological shield. The spent nuclear fuel and radioactive wastes, and certain selected components are shipped off-site. The structure needs to provide integrity during the period of time when significant quantities of radioactivity remain with the material in the entombment. Like in mothballing strategy, an appropriate continuous monitoring and surveillance systems are established. Again, the final dismantling is postponed indefinitely.

(iii) Immediate dismantling: The nuclear plant is dismantled right after end of its operation life. However, all the spent nuclear fuel and radioactive wastes, and any contaminated equipment and other materials with radio-activities above unrestricted levels are removed from the site. The site is cleared and released for unrestricted use.

The decommissioning cost and its cash-flow schedule would be different in each of the above cases. Furthermore, besides uncertainty in the cost of decommissioning, the time period required to decommission a nuclear power plant is also uncertain. For example, it took 15 years for decommissioning of Yankee Rowe NPP in USA, costing US $ 608 million. The site is still not returned to original condition or released for reuse because the spent nuclear fuel is stored in an on-site facility, which costs US $ 8 million per year for monitoring and security [7].

The estimates for decommissioning expenditure are usually made with the assumption that the task is to be carried out today with the presently available technology. These estimates are inflated to the future with an appropriate escalation rate to determine the liability at the end of the project life. The largest component of the cost is the project management cost: about 40%, followed by decontamination & dismantling cost: about 30%, waste management: about 25% and others 5%, as shown in Fig. 15, based on data from Ref. [7].

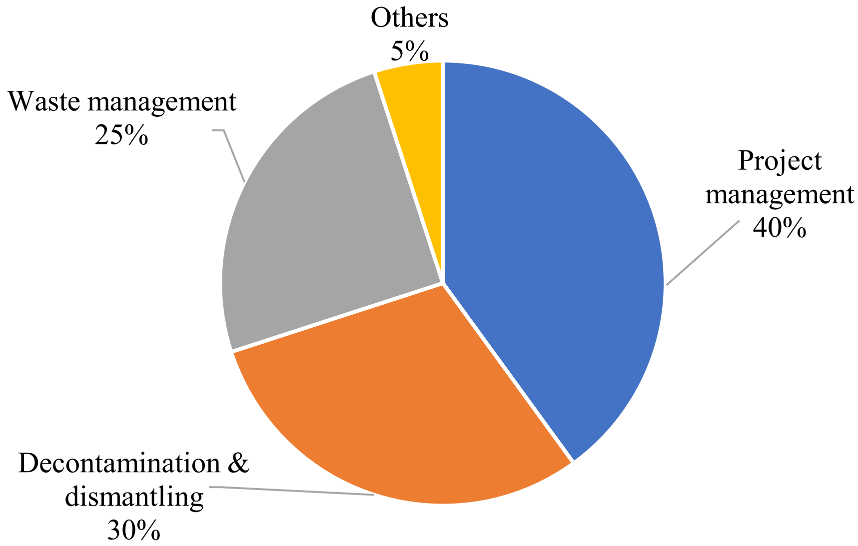

FIG. 15. Breakdown of decommissioning cost in main group of activities.

It would be clearly unrealistic to account for all these expenses at the beginning and include in the capital cost of the plant, as previously required under the International Account Standards [8]. It is however essential to assign right from the start the obligation to decommission the facility and restore the site, because the obligation arises when the plant is built. As such, appropriate arrangements have to be made at the beginning and the International Accounting Standards provisions have accordingly been amended. The general practice is to charge to total generation costs annually an estimated amount, called decommissioning allowance, and accumulate it over the operational life of the plant with periodic reassessment of the cost to generate sufficient funds for decommissioning. It can be calculated as below Eq. (54):

$$\textit{Annual decommissioning charge or allowance} = DC \cdot \frac{i}{\left[(1+i)^n - 1\right]} \tag{54}$$

where DC - Estimated decommissioning cost; i - interest rate that can be earned on decommissioning account; n - number of years for accumulating the fund.

For accumulating US $ 1 billion over a 40 years of operation life of a NPP, assuming 1% real interest rate, the annual decommissioning charge would be Eq. (55):

$$\textit{Annual decommissioning charge or allowance} = 1000 \cdot \frac{0.01}{\left[(1.01)^{40} - 1\right]} \tag{55}$$

$$= \textit{US \$ 20.46 million}$$

This amount is generally a separate accounting line for bookkeeping and can be added to the annual Fixed O&M cost.

4.7. CALCULATION OF LEVELIZED UNIT ENERGY COST (LUEC)

Once the estimates for all the cost components for a nuclear power project have been prepared, one can calculate the levelized unit energy cost – one of the main indicators for comparing the alternatives in terms of their economic competitiveness. The method for calculating LUEC is based on the concepts described in Section 2.

The LUEC calculations can be grouped into three main categories – capital cost component, fuel cost component and O&M cost component.

4.7.1. Capital cost component

This represents a fixed charge that would recover all the expenditure on constructing the plant. As explained earlier, the total expenditure incurred from the start of the project to the completion of the plant is considered as the total capital cost Eq. (56):

$$\begin{aligned} \textit{Total capital cost } &= \textit{Pure construction cost} + \textit{Owner's cost} + \textit{Other costs} \\ &+ \textit{Contingencies} + \textit{Escalation during construction} \\ &+ \textit{Interest during construction} \end{aligned} \tag{56}$$

One can calculate the annual capital charge Eq. (57) that would recover this total capital cost over the operation years, using the formula in section 2.3.

$$\textit{Annual capital charge } = \textit{ Capital recovery factor} \cdot \textit{Total capital cost} \tag{57}$$

where Capital recovery factor - $\frac{[\boldsymbol{r} \cdot (\mathbf{1}+\boldsymbol{r})^{\boldsymbol{n}}]}{(\mathbf{1}+\boldsymbol{r})^{\boldsymbol{n}}-\mathbf{1}}$; r - discount rate ($r \neq 0$); n - operation life

If we assume an average annual capacity factor, then average annual electricity generation would be Eq. (58):

$$\textit{Annual electricity production} = \textit{Capacity of plant} \cdot \textit{Capacity factor} \cdot 8760 \tag{58}$$

$$\textit{Capital cost component of LUEC} = \frac{\textit{Annual capital charge}}{\textit{Annual electricity production}} \tag{59}$$

If the electricity production in each year of operation is not the same, then one can use the formula Eq. (60) from section 3.6.

$$\textit{Capital cost component of LUEC} = \frac{\left[\sum\limits_{t=1}^{t=n} \frac{C_t}{(1+r)^t}{}^{t}\right]}{\left[\sum\limits_{t=1}^{t=n} \frac{E_t}{(1+r)^t}\right]} \tag{60}$$

where C_t - cost of construction in year t; E_t - electricity production in year t; r - discount rate; n - lifecycle of project.

4.7.2. O&M cost component

The O&M cost can be grouped into fixed O&M cost and variable O&M cost. As mentioned earlier, the fixed O&M cost is independent of the capacity/load factor of the plant and have to be paid whether or not the plant is operated, and includes items such as, salaries of regular staff, insurance, decommissioning allowance, etc., while other expenditures such as consumable materials and equipment, repair labour costs, etc., are proportional to the actual utilization of the plant. The plant management would prepare estimates for annual expenditure for operation and maintenance of the plant. Based on this estimate, one can calculate the O&M cost component of LUEC as shown below:

If electricity production is assumed same for all years Eq. (61).

$$O\ \&\ M\ Cost\ component\ of\ LUEC = \frac{Average\ annual\ O\ \&\ M\ expenditure}{Annual\ electricity\ production} \tag{61}$$

If electricity production and the O&M expenditure change each year of operation Eq. (62).

$$O\ \&\ M\ Cost\ component\ of\ LUEC = \frac{\left[\sum_{t=1}^{t=n} \frac{O\ \&\ M\ Expen_t}{(1+r)^t}\right]}{\left[\sum_{t=1}^{t=n} \frac{E_t}{(1+r)^t}\right]} \tag{62}$$

where O&M $Expen_t$ - O&M expenditure in year t; E_t - electricity production in year t; R - discount rate; n - operation life.

Since a nuclear power plant has an operational life extending to 40-60 years, any estimate for its O&M cost is subject to changes in prices of material, equipment, consumables, wages, etc. If we assume an average real escalation rate “e” in the O&M expenditure, then the formula for O&M cost component would become Eq. (63):

$$O\ \&\ M\ Cost\ component\ of\ LUEC = \frac{\left[\sum_{t=1}^{t=n} \frac{O\ \&\ M\ Expen_t \cdot (1+e)^t}{(1+r)^t}\right]}{\left[\sum_{t=1}^{t=n} \frac{E_t}{(1+r)^t}\right]} \tag{63}$$

where O&M $Expen._t$ - O&M expenditure in year t as estimated in base year prices; E_t - electricity production in year t; e - average real escalation rate in prices of O&M cost items; r - discount rate; n - operation life.

4.7.3. Fuel cost component

The method for calculating the fuel cost component of LUEC for a nuclear power plant is dependent on the technical considerations. For a light water reactor technology, the quantities of nuclear materials needed for the initial core and the annual reloads of fuel can be calculated as below:

For Initial Core

For a light water reactor of capacity P (kW_{th}), net thermal efficiency η (%/100), average power density in the reactor core at full power δ (kW/kg HM), the quantity of material for the initial core can be calculated as Eqs. (64), (65):

$$\begin{pmatrix} Fresh\ fuel\ load\ in\ reactor \\ for\ the\ first\ time \end{pmatrix} = \frac{Plant\ capacity}{Net\ thermal\ efficiency \cdot Average\ power\ density} \tag{64}$$

$$Material\ for\ initial\ core\left(kg\ of\ HM\right) = \frac{P(kW_{th})}{\eta(\%/100)\cdot\delta(kW/kg\ HM)} \tag{65}$$

The quantity of material for fuel fabrication would be slightly more than the mass of the fresh fuel to be loaded in the reactor due to fabrication losses and can be calculated as Eqs. (66), (67):

$$Fuel\ fabrication\left(kg\ of\ HM\right) = Material\ for\ initial\ core\cdot\left(1+Fabrication\ losses\right) \tag{66}$$

The fabrication losses are usually around 1%.

$$\begin{aligned} Expenditure\ on\ Fuel\ fabrication = {} & Fuel\ fabrication\left(kg\ of\ HM\right) \\ & \cdot Cost\ of\ fabrication\ service\left(\$/kg\ HM\right) \end{aligned} \tag{67}$$

Enrichment is a special process, and the enrichment effort is measured in separative work units (SWU) per kg of enriched uranium product (P) Eqs. (68), (69):

$$\frac{SWU\ F}{P} = V\left(xp\right) - V\left(xt\right) + \frac{F}{P}\left(V\left(xt\right) - V\left(xf\right)\right) \tag{68}$$

$$V(x) = (2x-1)\ln\frac{x}{x-1} \tag{69}$$

where $V(x)$ - 'value function' at the enrichment fraction x, and Eq. (70):

$$\frac{F}{P} = \frac{(xp - xt)}{(xf - xt)} \tag{70}$$

where xp - enrichment of product in ^{235}U; xf - enrichment of feed in ^{235}U; xt - enrichment of tails in ^{235}U.

$$\begin{aligned} Enrichment\ (kg\ SWU) = {} & Material\ for\ fuel\ fabrication\cdot(1+Fabrication\ losses) \\ & \cdot\frac{SWU\ F}{P} \end{aligned} \tag{71}$$

$$\begin{aligned} Expenditure\ on\ enrichment = {} & Enrichment\left(kg\ SWU\right) \\ & \cdot Cost\ of\ enrichment\ service\left(\$/kg\ SWU\right) \end{aligned} \tag{72}$$

The feed material for enrichment is UF_6 which is produced by a chemical conversion process, which has some conversion losses Eqs. (73), (74):

$$\begin{aligned} Conversion\left(kg\ HM\right) = {} & Material\ for\ initial\ core\cdot\left(1+Fabrication\ losses\right) \\ & \cdot\frac{xp-xt}{xf-xt}\cdot\left(1+Conversion\ losses\right) \end{aligned} \tag{73}$$

$$Expenditure\ on\ conversion = Conversion\left(kg\ HM\right) \cdot Cost\ of\ conversion\ service\left(\$/kg\ HM\right) \tag{74}$$

The quantity of natural uranium in the form of Yellow Cake (U_3O_8) required for the initial core can be calculated as Eqs. (75), (76):

$$Natural\ uranium\left(kg\ of\ U_3O_8\right) = Material\ for\ conversion \cdot \left(\frac{Mass\ of\ U_3O_8}{kg\ HM}\right) \tag{75}$$

$$Expenditure\ on\ purchase\ of\ natural\ uranium = Natural\ uranium\left(kg\ of\ U_3O_8\right) \cdot Price\ of\ U_3O_8\left(\$/kg\ U_3O_8\right) \tag{76}$$

The total direct cost for the initial core Eq. (77) is the sum of expenditure on purchase of uranium, conversion, enrichment, fuel fabrication.

$$Direct\ cost\ of\ initial\ core = \sum_{s=1}^{4} Expend_s \tag{77}$$

where s - stage 1 to 4, uranium, conversion, enrichment, fuel fabrication; $Expend_s$ - expenditure on stage s.

Since these expenditures occur at different times, the interest charges can be calculated as Eq. (78):

$$Interest\ charges\ on\ direct\ cost\ of\ Initial\ core = \sum_{s=1}^{4} Expend_s \cdot \left\{\left(1+i\right)^{lt_s} - 1\right\} \tag{78}$$

where s - stage 1 to 4, uranium, conversion, enrichment, fuel fabrication; $Expend_s$ - expenditure on stage s; lt_s - lead time for stage s, - time of expenditure ahead of initial core loading; i - interest rate.

The total cost of the initial core Eq. (79) is the sum of direct cost and the interest charges.

$$Total\ cost\ of\ initial\ core = Direct\ cost\ of\ initial\ cost + interest\ charges\ on\ direct\ cost \tag{79}$$

As the initial core will contribute to the electricity generation for several years, the practice is to amortize this cost over the operating life of plant. As such, one can calculate the annual charge for initial core fuel cost Eq. (80):

$$\begin{aligned} Annual\ charge\ for\ initial\ core &= Total\ cost\ of\ initial\ core \cdot Capital\ Recovery\ Factor \\ &= Total\ cost\ of\ initial\ core \cdot \frac{r(1+r)^n}{(1+r)^n - 1} \end{aligned} \tag{80}$$

where r - discount rate; n - operation life.

The method for calculating the quantities of material for each reload is same as for the initial core, as shown below Eqs. (81) – (89):

$$Fresh\ fuel\ load\ in\ reactor = \frac{Plant\ capacity}{Net\ thermal\ efficiency \cdot Average\ burn\text{-}up} = \frac{P(MW_{th})}{\eta(\%\ /\ 100) \cdot Q(MWD\ /\ kg\ HM)} \tag{81}$$

$$Fuel\ fabrication\ for\ reload\ (kg\ of\ HM) = Material\ for\ reload \cdot (1 + Fabrication\ losses) \tag{82}$$

$$Expenditure\ on\ fuel\ fabrication\ for\ reload = Fuel\ fabrication\ for\ reload\ (kg\ of\ HM) \cdot Cost\ of\ fabrication\ service\ (\$/kg\ HM) \tag{83}$$

$$Enrichment\ for\ reload\ (kg\ SWU) = Fuel\ fabrication\ for\ reload \cdot (1 + Fabrication\ losses) \cdot \left(\frac{SWU\ F}{P}\right) \tag{84}$$

$$Expenditure\ on\ enrichment\ for\ reload = Enrichment\ for\ reload\ (kg\ SWU) \cdot Cost\ of\ enrichment\ service\ (\$\ /\ kg\ SWU) \tag{85}$$

$$Conversion\ for\ reload\ (kg\ HM) = Material\ for\ reload \cdot (1 + Fabrication\ losses) \cdot \frac{xp - xt}{xf - xt} \cdot (1 + Conversion\ losses) \tag{86}$$

$$Expenditure\ on\ conversion\ for\ reload = Conversion\ (kg\ HM) \cdot Cost\ of\ conversion\ service\ (\$\ /\ kg\ HM) \tag{87}$$

$$Natural\ uranium\ for\ reload\ (kg\ of\ U_3O_8) = Material\ for\ conversion\ for\ reload \cdot \left(\frac{Mass\ of\ U_3O_8}{kg\ HM}\right) \tag{88}$$

$$\left(\begin{array}{l} Expenditure\ on\ purchase \\ of\ Natural\ uranium\ for\ reload \end{array}\right) = Natural\ uranium\ (kg\ of\ U_3O_8) \cdot Price\ of\ U_3O_8\ (\$\ /\ kg\ U_3O_8) \tag{89}$$

The total direct cost for the reload Eq. (90) is the sum of expenditure on purchase of uranium, conversion, enrichment, fuel fabrication for the reload.

$$Direct\ cost\ of\ reload = \sum_{s=1}^{4} Expend_s \tag{90}$$

where s - stage 1 to 4, uranium purchase, conversion, enrichment, fuel fabrication; $Expend_s$ - expenditure on stage s,

$$Interest\ charges\ on\ direct\ cost\ of\ reload = \sum_{s=1}^{4} Expend_s \cdot \left\{ \left(1+i\right)^{lt_s} - 1 \right\} \tag{91}$$

where s - stage 1 to 4, uranium, conversion, enrichment, fuel fabrication for reload; $Expend_s$ - expenditure on stage s for reload; lt_s - lead time for stage s - time of expenditure ahead of reload; i - interest rate.

The total cost of the Reload Eq. (92) is the sum of direct cost and the interest charges.

$$Total\ cost\ of\ reload = Direct\ cost\ of\ reload + interest\ charges\ on\ direct\ cost \tag{92}$$

If we assume the Reload would take place every year, then the total annual fuel cost Eq. (93) would be the sum of annual charge for the initial core and the annual reload cost.

$$Total\ annual\ fuel\ cost = Annual\ charge\ for\ initial\ core + Total\ cost\ of\ annual\ reload \tag{93}$$

And finally, the fuel cost component of LUEC can be calculated as follows.

If the electricity production is assumed to be same for all years of the operation Eq. (94):

$$Fuel\ cost\ component\ of\ LUEC = \frac{Total\ annual\ fuel\ cost}{Annual\ electricity\ production} \tag{94}$$

During the operational life (40-60 years), the cost of fuel reloads may change due to changes in prices of uranium and the fuel cycle services. If we assume an average real escalation rate “e” in the annual reload expenditure, then the fuel cost component would become Eq. (95):

$$\begin{pmatrix} Fuel\ cost \\ component \\ of\ LUEC \end{pmatrix} = \frac{Total\ cost\ of\ initial\ core + \left[\sum_{t=1}^{t=n} \frac{Cost\ of\ reload_t \cdot (1+e)^t}{(1+r)^t} \right]}{\left[\sum_{t=1}^{t=n} \frac{E_t}{(1+r)^t} \right]} \tag{95}$$

where Cost of reload.t - total cost of reload in year t as estimated in base year prices; E_t - electricity production in year t; e - average real escalation rate in total cost of reload; r - discount rate; n - operation life.

A special component of nuclear fuel cost is the back-end cost. For once-through (open) fuel cycle, the back cost represents the cost of managing the spent nuclear fuel. This includes storage and final disposal of the spent fuel. The common practice is to annually charge an adequate amount for this purpose. This amount can be calculated as Eq. (96), (97):

$$Annual\ discharge\ of\ Spent\ fuel = \frac{P(MW)}{\eta(\%/100)\cdot Q(MWD/kgHM)} \quad (96)$$

$$\begin{aligned} Annual\ cost\ for\ back\text{-}end &= Annual\ discharge\ of\ Spent\ fuel\,(kg\ HM) \\ &\cdot Cost\ of\ back\text{-}end\,(\$/kg\ HM) \end{aligned} \quad (97)$$

The back-end cost component can thus be calculated as Eq. (98):

$$Back\text{-}end\ cost\ component\ of\ LUEC = \frac{Annual\ cost\ for\ back\text{-}end}{Annual\ electricity\ production} \quad (98)$$

This cost component is usually added to the fuel cost. Adding all the components of LUEC gives the total levelized unit electricity cost. For a typical LWR nuclear power plant, about 60% of the LUEC is due to Investment and 20% each for O&M and Fuel Cost. Figure 16 shows a typical break-down of LUEC for an LWR plant.

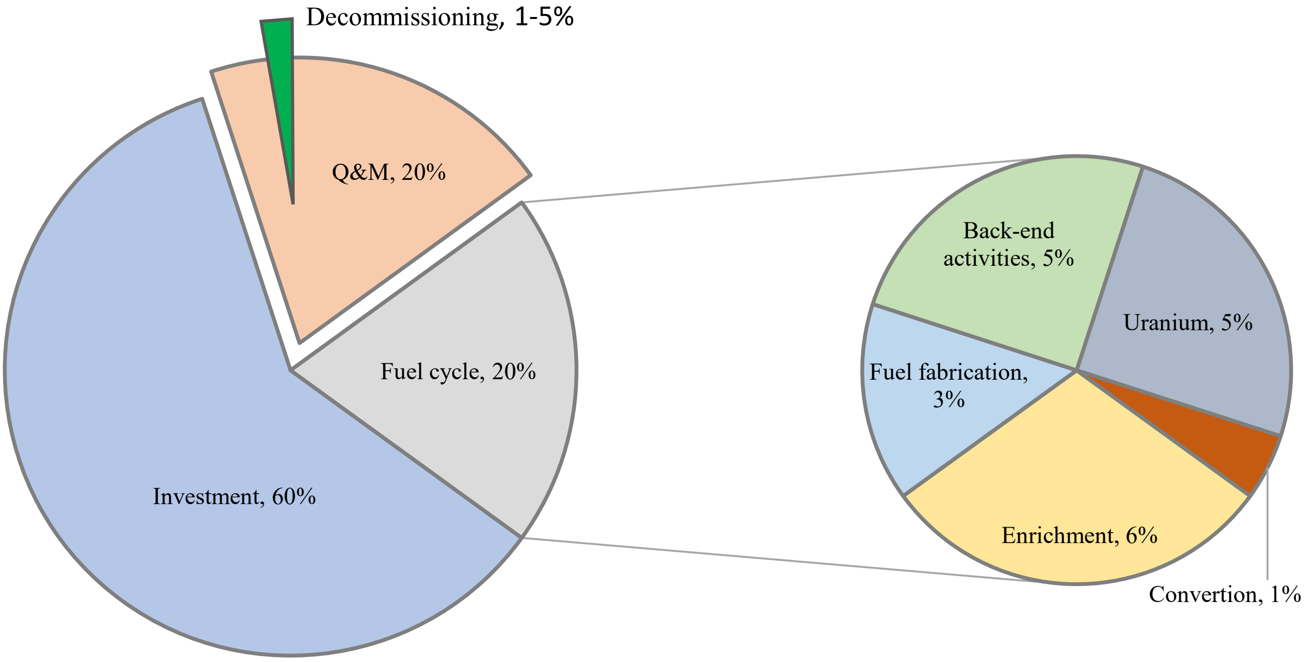

FIG. 16. Break down of generation cost of a nuclear power plant. Legend: O&M – operation and maintenance.

It can be noted that the cost of uranium is only 5% of the total cost of electricity generation from a nuclear power plant. This implies that if the uranium prices increase, the cost of electricity generation from a nuclear power plant will not be influenced significantly. Figure 17 shows the impact of doubling the fuel prices on generation cost of different power sources. In the case of nuclear, the impact is insignificant whereas for coal or gas-based power plants, the fuel price can have a considerable impact on the generation cost and thereby on the comparative ranking of the options. As such, the assumptions about future fuel prices become a critical aspect of the comparative assessment.

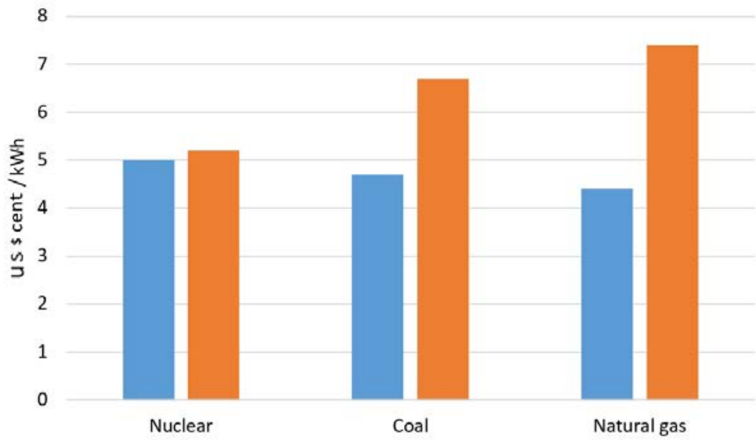

FIG. 17. Impact of doubling the fuel prices on generation cost of different power plants.

5. ELECTRIC SYSTEM EFFECTS ON ECONOMICS OF ALTERNATIVES

5.1. SYSTEM COSTS

The electricity delivery to end-users, with adequate reliability, involves integrated operation of production, transmission and distribution activities. The system is operated in real time by balancing supply and demand based mainly on technical and economic considerations. Additionally, in some cases, the environmental and regulatory aspects can also affect the system operation. The economic considerations include (i) cost of production by different power plants, (ii) cost of transmission of power which is dependent on the location of power plants and load centers, (iii) cost of distribution, and (iv) cost of maintaining quality in terms of reliability of supply and security of system. As such, the production cost is only a part of the total cost of delivering electricity to the end-users. Though each component is highly dependent on the specific profile of an electric system, the production cost is generally less than 50% of the total cost of delivery. It is therefore essential to take into account all these costs while deciding on selection of power plants for future capacity expansion. The methodology described in section 3 for economic comparison of different power plants has its limitations as each alternative plant is considered in isolation without taking into account its interaction with the entire system. For a comprehensive economic comparison, the system effects of different type of power plants have to be accounted for.

5.2. GRID COSTS

The location of a power plant influences the grid cost. Various types of power plants have specific locational limitations, e.g., availability of cooling water for thermal and nuclear power plants, suitability of a site for hydro power plant, etc. Depending on the location of a power plant, connecting it to the grid may require significant investment for strengthening and extending the grid. The investment for strengthening and extending the grid to plant location, in turn, depends on distance from the existing grid to the plant, size of the plant and its technical aspects, terrain on-the-way, right-of-way, etc. In addition, transmission losses tend to increase when electricity has to be moved over long distances, therefore increasing the overall per unit cost of delivering electricity to the end-consumers.

In some cases, grid connection costs are included in the total project cost of the power plant and borne by the plant developer, and implicitly included in the plant-level production cost. In other cases, these costs are considered as system cost and arranged by the transmission company. The grid costs can run into billions of US dollars and can adversely affect the competitiveness of the power plant.

For example, the Levy county nuclear power plant, Florida USA, approved for construction in 2008, was estimated to require 175 miles of new transmission lines and several grid upgrades. The cost estimate for the 2 units of AP1000 plant was US $ 14 billion and for transmission lines US $ 3 billion[7]. Later the project was cancelled due to high cost.

[7] https://www.world-nuclear-news.org/NN_Levy_nuclear_project_moved_back_by_three_years_0205122.html

5.3. SYSTEM RESERVE COST

All power systems keep some reserve capacity – both in the generation system as well as in the transmission & distribution system, see Table 11. These reserves can be categorized in two main groups: cold reserves and hot reserves. Cold reserves are needed during the period when power plants and transmission & distribution equipment are taken out of service for regular maintenance. When a power plant is under maintenance, the reserve generation capacity is brought on-line to produce electricity in its place. This type of reserves is also needed to cover up the seasonal variation in production capability of some plants, like hydro power plants. The quantum of reserve capacity depends on the types and sizes of the power plants in the system. Keeping this reserve capacity requires additional costs at the system level.

TABLE 11. COMPARISON OF INSTALLED CAPACITY AND PEAK DEMAND (2013)

	Installed capacity GW	Peak demand GW
United States	1 110	782
Japan	311	159
France	126	92
Republic of Korea	97	79
Italy	114	61
United Kingdom	86	53
Turkey	60	43
Mexico	63	42
Spain	100	40

The hot reserves, also called spinning reserves, can further be sub-grouped into primary, secondary and tertiary reserves. These are meant to cover up the situation arising from loss of production due to unforeseen outages of power plants or transmission lines, and thus needed on a short notice. When a generating unit trips, the system frequency falls rapidly, as shown in Fig. 18. The drop in frequency is bigger and faster if a larger unit trips.

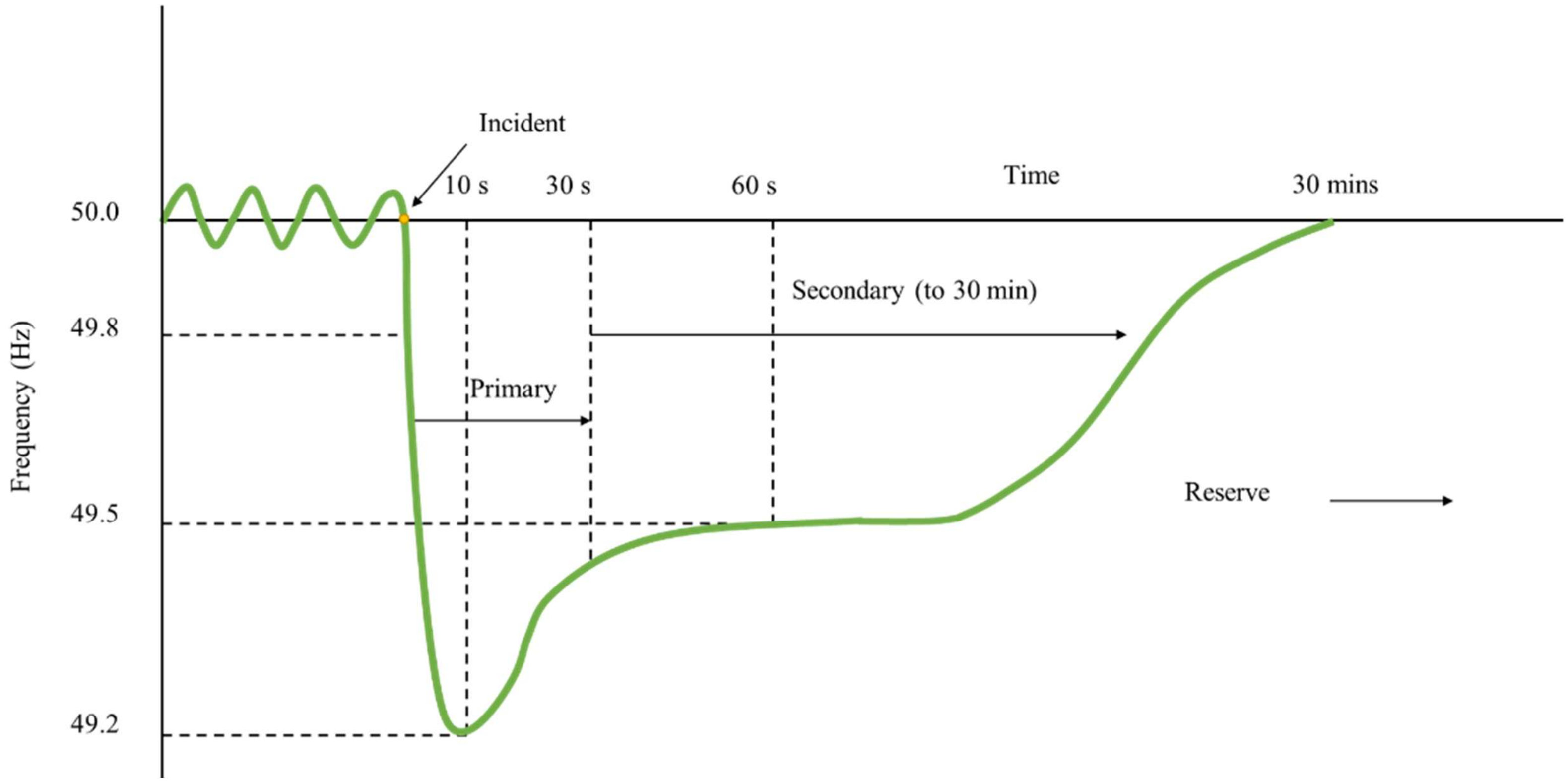

FIG. 18. Role of hot reserves in a power system.

The primary reserves are needed within a few seconds of the loss of a generator while the secondary reserves are typically called upon after 30 seconds of the incident, relieving the primary reserves to cover up for any other incident. Subsequently, tertiary reserves are used to relieve the secondary reserves after 60 second. Typically, the primary reserves are provided by the generating units operating in an automatic frequency control mode and at less than full load, while the secondary and tertiary reserves are provided by the generating units with fast ramp rate and those which are kept operating less than their full load and called to increase their output when frequency falls.

For maintaining the adequate level of reliability of supply and security of the network, the general practice is to keep hot reserves at least equal to capacity of the largest power unit connected to the grid. If a 1000 MW nuclear power unit is added to the system, a hot reserve capacity of 1000 MW would be required in the system, ready to make-it-up if the nuclear plant trips. Maintaining this operating reserve capacity obviously adds to the cost of the system. Alternatively, if two units of 500 MW each fossil-fueled power plant are added, the operating reserve requirement would be 500 MW – following the same principle of the largest unit, with correspondingly lower additional cost. A loss of 10% of generation can result in a frequency drop by 3 – 5 Hz within a minute, whereas a maximum allowed deviation is typically 0.1 – 0.2 Hz. This puts a limit of the size of a unit in a system – typically a single unit is less than 10% of the maximum load.

Besides the size of the largest unit in the system, the quantum of the reserve capacity required also depends on the mix of different types of power plants in the system. If the system contains larger share of nuclear and/or coal power plants, which have slower ramp rate, and thus limited ability to provide hot reserves, more units of other power plants will be needed but operated at lower load level. Furthermore, the configuration and strength of the transmission network influence the quantum of the reserve capacity needed. A system interconnected with the neighboring system would need smaller reserve capacity as these resources can be shared among the interconnected systems. In the European network, the requirement for primary reserves is 3000 MW or equivalent of two 1500 MW nuclear plants. In the PJM system, USA, keeps primary reserves equivalent to only 1.1% of the peak load, because the PJM system is well connected with other systems[8].

If a system has a sizeable capacity of such sources on aggregate basis, the firm capacity from these resources may be limited because of the uncertainties in their power output. Consequently, the required quantum of hot reserves in the system would be much larger.

5.4. BALANCING COSTS

As mentioned earlier, the supply-demand in an electric system is balanced in real time by adjusting the output of electricity generating units. As the demand increases the output of some units is increased and when demand decreases the output is reduced. The task of balancing become more difficult if the demand is changing rapidly or the generation capability of some plants is varying quickly, or both changes are happening swiftly. A typical daily load curve is shown in Fig. 19.

[8] https://slideplayer.com/slide/10713873/

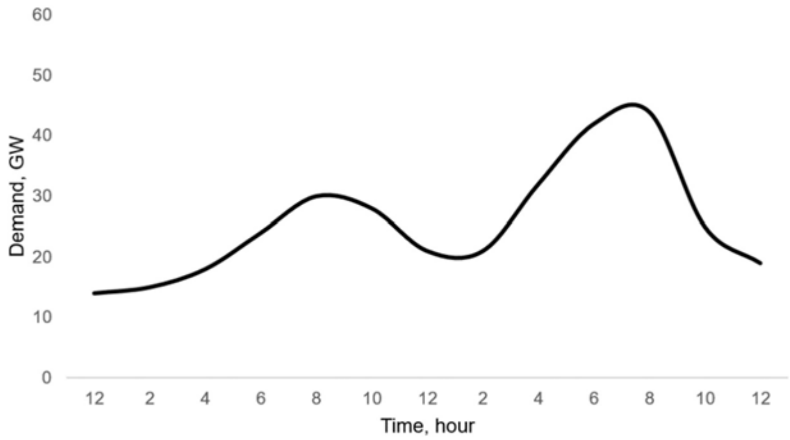

FIG. 19. A typical daily load curve.

For meeting this profile of demand, some generating units will run 24 hours, while others for a few hours in a day. The per unit production cost of those which are underutilized, i.e., operating at reduced capacity factor, will increase. If the load pattern is such that most of the plants are used less than their generation capability, the overall system cost will increase. In an electric system with sizeable capacity based on renewable sources, the system costs would further increase due to natural variability of their generation, forcing further adjustment to the output of other plants. For example, the variation in wind and solar, would require more frequent changes to the dispatch schedule of other power plants in the system and necessitate more frequent ramping and cycling of other plants, resulting in inefficiencies in fuel consumption and plant utilization. This would result in higher costs for the system. In some cases, the variation in wind and solar may require curtailing their own output if that cannot be utilized economically. This is also an additional cost to the system because in such cases, the renewable sources would be underutilized, leading to higher per unit
generation cost.

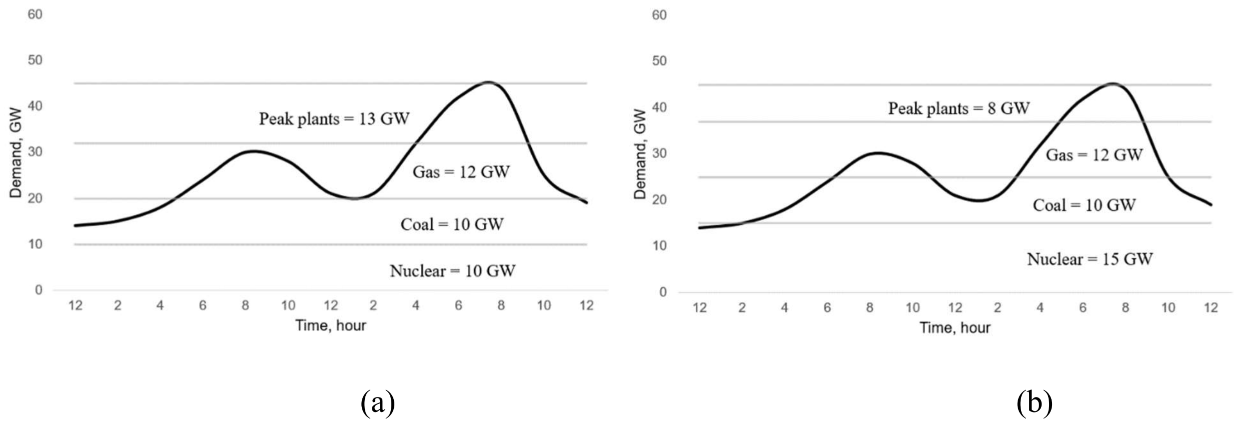

FIG. 20. Effect of large power plants on utilization of plants

A converse situation may also arise in a system if there are some bigger generating units which have limited flexibility and have to be used almost at a constant load, e.g., nuclear power plants. In such a situation, the variation in demand would force the rest of power plant in the system to adjust their output for balancing supply and demand causing higher costs. For example, as shown in the Fig. 33, if a system has 45 GW as the peak load on a day which is met by 10 GW nuclear, 10 GW coal, 12 GW gas and 13 GW peaking plants. Assuming LUEC of nuclear is lower than that for peaking plants, we consider replacing 5 GW of peaking capacity by nuclear power. Since nuclear plants have limited flexibility, all the 15 GW of nuclear capacity has to be operated at the based load position. This would push up the coal and gas plants on the load curve, resulting in reduced generation from them. The reduced utilization of coal and gas plants would increase their per unit cost. Depending upon cost differential between nuclear and peaking plants, the overall cost of generation may increase.

Some modern nuclear power plants have significant flexibility, i.e., can change their output to some extent as needed, but because of the effect of thermal transients during load changes, there may be restrictions due to safety reasons and operating license regulations. Furthermore, if a nuclear power plant is underutilized due to load following operation, its economics would be worsened, (for example because the levelized unit energy cost is dependent on capacity factor). The fuel consumption per unit generation, in such a case, will increase and spent fuel inventory enlarged.

5.5. ASSESSMENT OF SYSTEM COST

As mentioned earlier, the system cost arising due to introduction of specific technologies in an existing grid is dependent on a number of factors, including pattern of electricity demand, characteristics of the existing generating technologies in the system, grid configuration and various aspects of the proposed technology for introduction, e.g., site location, size of a unit, technical nature of the technology, etc. The technology characteristics are critical for the flexibility available in a system to balance the supply-demand in real time. Table 12, based on data from Ref. [9], compares typical operational characteristics of nuclear, coal and gas power plants. Clearly, nuclear power plants offer very limited flexibility whereas gas turbines provide swift adjustment to their load to match the variation in demand and/or changing supply from wind and solar.

TABLE 12. OPERATIONAL CHARACTERISTICS OF NUCLEAR, COAL AND GAS POWER PLANTS

	Start-up time	Maximal change in 30 sec	Maximum ramp rate (% / min)
Open cycle gas turbine (OCGT)	10 - 20 min	20 - 30%	20% / min
Combined cycle gas turbine 9CCGT)	30 - 60 min	10 - 20%	5 - 10% / min
Coal plant	1 - 10 hours	5 - 10%	1-5% / min
Nuclear power plant	2 hours – 2 days	Up to 5%	1-5% / min

The system cost can widely vary for conventional dispatchable technologies as well as from country to country. Figure 21 compares system cost of nuclear, coal- and gas-based power plants in selected countries, as estimated in a study [9] (the estimates shown correspond to a 10% share for each of these technologies in the respective systems). It can be noted that nuclear imposes higher system cost in all these countries, followed by coal and then gas based plans. The main reason is the size of nuclear power units and the special characteristics of nuclear power reactors which need to be operated in stable conditions. It may be pointed out that the system cost in these countries is relatively low because the grid system in these countries is strong and well interconnected. On the other hand, the system cost for the same technologies in a developing country or a country with small grid size can be very high.

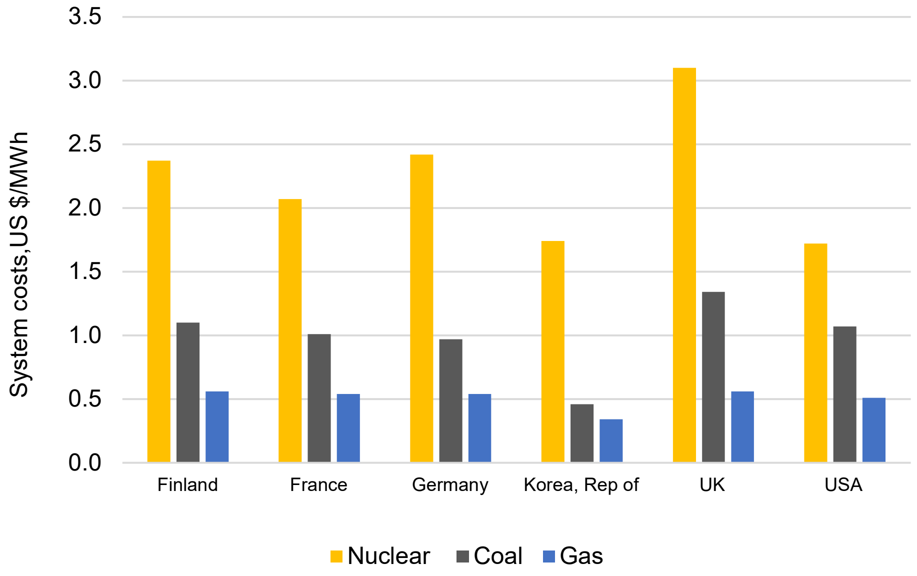

FIG. 21. System cost estimates for nuclear, coal and gas power plants.

Several methodological tools have been developed to assess the system cost imposed by the introduction of different electricity generation technologies. These tools have attained higher importance due to the need for assess the system effects of introducing renewable technologies which give rise to very high system cost due to their intermittent nature. Some tools capture most of the operational details and allow system reliability analyses by simulating the operation of the entire system and estimating the operation cost. Such a detailed analysis is not feasible in the case of tools focusing on evaluation of long-term capacity expansion. A compromise on the operational details is thus needed incorporating only the main aspects that influence the overall system cost of delivering electricity to end-users. The IAEA energy models – WASP and MESSAGE, capture the system effect in long term capacity expansion optimization process, and allow realistic assessment of alternative technologies in a system level comparison.

5.6. ASSESMENT OF SYSTEM COST WITH MESSAGE-NES MODELLING

The IAEA's energy model MESSAGE - Model for energy supply strategy alternatives and their General environmental impacts (MESSAGE), which supports energy analysis and planning, and has been adapted and extended by INPRO for nuclear energy system modelling, in particular for material flow analysis to support nuclear energy system assessment. The methodology of MESSAGE is based on the optimization of an overall system cost function under a set of constraints on energy resource extraction, fuel availability and trade, new investments, market penetration for new technologies, environmental emissions and waste generation, to meet demand for energy. The technical and economic details of the energy system under study are central to modelling with MESSAGE. This includes defining the categories of energy forms considered (e.g. primary energy, final energy and useful energy), the fuels (commodities) and associated technologies for conversion and delivering energy forms to provide energy services. Technologies are defined by their inputs and outputs, their efficiency and their other technical characteristics like variability and flexibility.

The model allows a flexible framework to represent details of the electricity system and evaluate economic competitiveness of alternative energy/electricity technologies. The user can model the technical aspects of various power plants and simulate their operation in an electric grid - for example which generating units would operate in the base load, which would provide the peaking energy, and which would provide systems reserves. The model determines these roles for each of the power plant in the system based on their technical characteristics and their operation costs. A power plant which has a high capital cost but lower fueling cost would be used to its maximum and assigned based-load duty, while a plant which has lower capital cost but high fueling cost would be used for shorter period and assigned peaking duty.

The optimal generation mix and capacity additions are influenced by the operational roles determined during the optimization process. Furthermore, since electricity has to be provided at exactly the same time it is required, the model simulates this situation and keeps reserve capacity to ensure system reliability. This requirement would also influence the capacity additions.

This simultaneous system-wide optimization determines the true economic competitiveness of alternative technological options.

In order to assess the system cost for different technologies, one can develop MESSAGE scenarios for a system with and without system reliability considerations, i.e., with and without system reserves constraints. The difference in the total cost would represent the system cost effect. The procedure can be repeated for different technologies by including them one by one in the assessment.

6. ENVIRONMENTAL IMPACTS AND EXTERNAL COSTS

6.1. MAIN ENVIRONMENTAL IMPACTS FROM ENERGY

The environmental and health implications of electricity generation are a major factor influencing the choice among alternative energy sources. Use of all energy sources do put burden on the environment, though different in nature and severity, and cause risks for human health. Main environmental pollutants and wastes generated, and interferences with nature caused by different energy technologies are listed in Table 13.

TABLE 13. ENVIRONMENTAL BURDENS FROM DIFFERENT ENERGY TECHNOLOGIES

Fossil fuel based energy technologies	CO_2, SO_2, NO_2, particulates, liquid and soil wastes
Nuclear energy	Low & medium level rad wastes, high level waste
Hydro	Land submergence, water logging, seismic activity, flora & fauna, people displacement
Solar	Toxic wastes from production of PV systems

In the case of fossil fuels-based technologies, oxides of sulphur and nitrogen, particulates and CO_2 are produced during combustion. The quantities of these pollutants are mainly dependent on the quality of fuel and technology of conversion. In the case of coal fired power plants, largest quantities of these pollutants are emitted. Besides atmospheric emission, fossil fuels-based technologies produce large amounts of wastes, which have to be disposed.

In general, the modern fossil fuel technologies are fitted with abatement equipment to remove sulphur and nitrogen oxides, and particulates from the flue gases. Still some amount of these pollutants is released which can cause environmental damage and pose significant risk to public health.

Furthermore, the fossil fuels-based technologies also release some radioactive material naturally present in these fuels. For example, combustion of coal releases radiation similar in magnitude to the routine releases from the nuclear industry, in terms of its potential biological consequences. Likewise, natural gas production and use releases radon – a radioactive gas naturally present in the gas – to the atmosphere, which is also comparable to radiation arising from the civil nuclear power industry. Additionally, trace quantities of other organic compounds and heavy metals that are known carcinogens are released from coal-fired plants.

In the case of nuclear power, small quantities of radiation are released to the environment during reactor operation and at fuel production and spent fuel management facilities. These releases are constantly monitored and kept below permissible levels. The magnitude of these releases corresponds, on average, to less than 0.1% of the radiation from natural background - radioactivity arising from radioactive minerals in the ground and from cosmic rays. This is the result of strict regulations practiced in the nuclear industry. In fact, the radiological impacts from nuclear power are comparable to those associated with fossil fueled power generation.

The main concern about nuclear power among the public is the perceived risk of a major accident resulting in the release of large quantities of radioactive material into the environment, and with consequent loss of life and ecological and economic damage.

Nuclear power industry, however, produces high level radioactive waste or spent nuclear fuel to be managed and disposed of, which would remain highly radiotoxic for thousands of years. Handling this issue is challenging and require significant expenditure.

Hydro power – known as a clean source of energy, also has its environmental impacts. These include land submergence, water logging, seismic activity, damage to flora and fauna, and displacement of people. These environmental and social impacts are very site specific and can be very critical, particularly displacement of people, for some projects annulling their feasibility.

Other renewable sources, like solar, also impose a toll on the environment. The production of photovoltaic systems generates highly toxic waste. In addition, the materials used per unit of electricity generation for installation of these systems and disposing of them or recycling them at the end of their useful life produces large quantities of wastes.

Table 14, based on data from Ref. [10], compares the emissions of harmful pollutant from different types of power plants. Here the emission indicated for nuclear power are those arising from the fuel cycle activities.

TABLE 14. EMISSION OF HARMFUL POOLUTANTS FROM DIFFERENT TYPES OF POWER PLANTS*

Fuel	Coal		Natural gas			
Technology	Hard coal	Lignite	Combined cycle	Stream turbine	Bioenergy	Nuclear
SO_2	530-7 680	425-27 250	1-324	0-5 830	40-490	11-157
NO_x	540-4 230	790-2 130	100-1 400	340-1 020	290-820	9-240
PM	17- 9 780	113-947	18-133	Insufficient data	29-79	0-7

All these environmental burdens cause different types of environmental effects that range from local, regional to global scale. For example, combustion of fossil fuels releases of carbon dioxide and nitrous oxides, both of these gases are greenhouse gases and cause heat-trapping in the atmosphere. Apart from water vapors in the atmosphere, carbon dioxide is the main contributor to climate change, which currently accounts for some 50% of the global warming effect of the atmosphere. This effect is at the global level.

Acidification is the major damage caused by the emissions of sulphur and nitrogen oxides from fossil fueled power plants.
The emissions of SO_2, NO_x, etc. give rise to severe environmental impacts at regional scale through acidification. These pollutants travel long distances and get chemically transformed into acids which deposit on large areas far away from the plant site, and cause considerable damages to human health, vegetation, buildings and other receptors in the area. Oil spills in sea, hydro dam induced seismic activity and radioactive releases from a major nuclear accident are also regional scale environmental impacts caused by the energy system.

Urban smog caused by pollutants like particulates, SO_2, NO_x, VOCs, etc. is another severe environmental impact arising from fossil fuels. Land disruption due to mining, hydro dams, etc., and deforestation, are also local level impacts. Figure 35 summarizes different environmental effects caused by energy technologies.

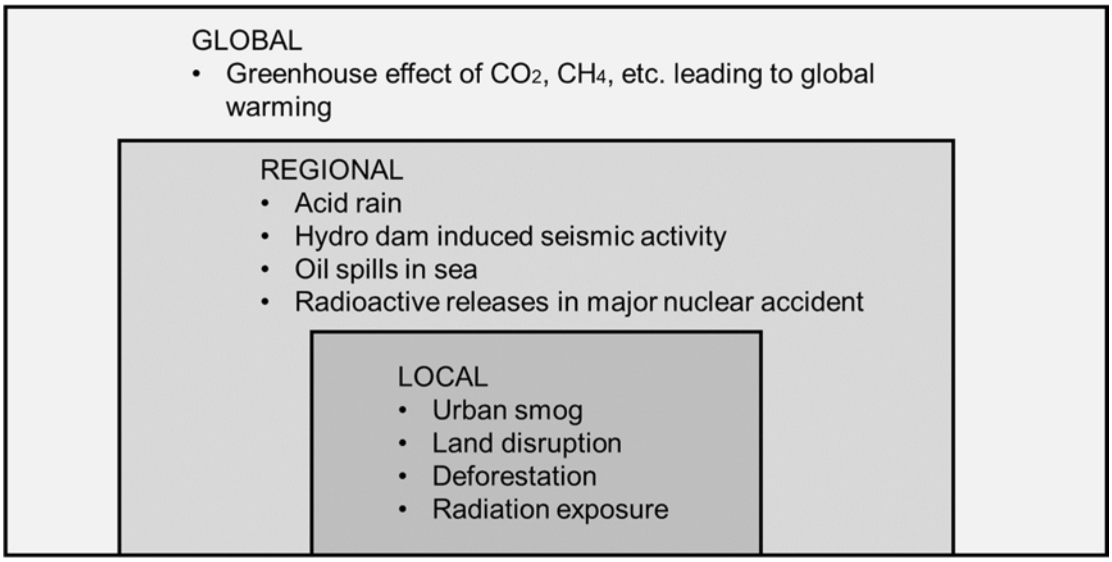

FIG. 22. Various environmental impacts at local, regional and global scale.

It is desirable to minimize the environmental damages and reduce risks for human health. For this purpose, environmental regulations are enforced for limiting the emissions and proper disposal of wastes. Table 15 shows limits for sulphur dioxide recommended by the World Bank for developing countries. As can be noted, the limits are more stringent for the areas which are already polluted. Each country establishes its national regulations for the protection of environment. The energy/electricity producers incur significant expenditure to comply with environmental regulation. These expenditures need to be attributed to the respective energy options while comparing their economic costs and benefits.

TABLE 15. ENVIRONMENTAL LIMITS FOR SULPHUR DIOXIDES.

SO_2 Background levels ($\mu g/m^2$)			Criterion I	Criterion II
Background AIR quality (SQ_2 Basis)	Annual average	Maximum in 24 hour interval	Maximum SO_2 emissions (Ton)	Maximum allowable ground level increment to ambient ($\mu g/m^2$)
Unpolluted	<50	<200	500	50
Moderately polluted	—	—	—	—
Low	50	200	500	50
High	100	400	100	10
Very polluted	>100	>400	100	10

6.2. ENVIRONMENTAL DAMAGE COSTS

All the adverse environment impacts of electricity generation eventually cause damages to human health, botanical and zoological life forms, buildings/structures, etc. It is recognized that these damages may offset all the benefits of using electricity/energy. It is therefore important to quantify the damages and assess the cost of damages, and to take into account these costs in comparing various electricity technologies.

It can be quite difficult to quantify the environmental damages and convert them to monetary values. There are large uncertainties in quantification of environmental damages and any valuation method remains very subjective. The estimates are highly dependent on country conditions and the underlying assumptions.

For assessment of environmental damage, it could be noted that the environmental impacts associated with different electricity sources are not confined to the generation stage but extend over the entire fuel chain – from extraction, processing, transportation and use of fuels, to final disposal of waste. The impacts arising from construction of facilities (and dismantling them at end of their lives) are also to be included. Figure 23 compares the external costs for different electricity generation technologies estimated for EU countries. It can be noted that the environmental damage cost can be as high as the electricity generation cost for some of the technologies.

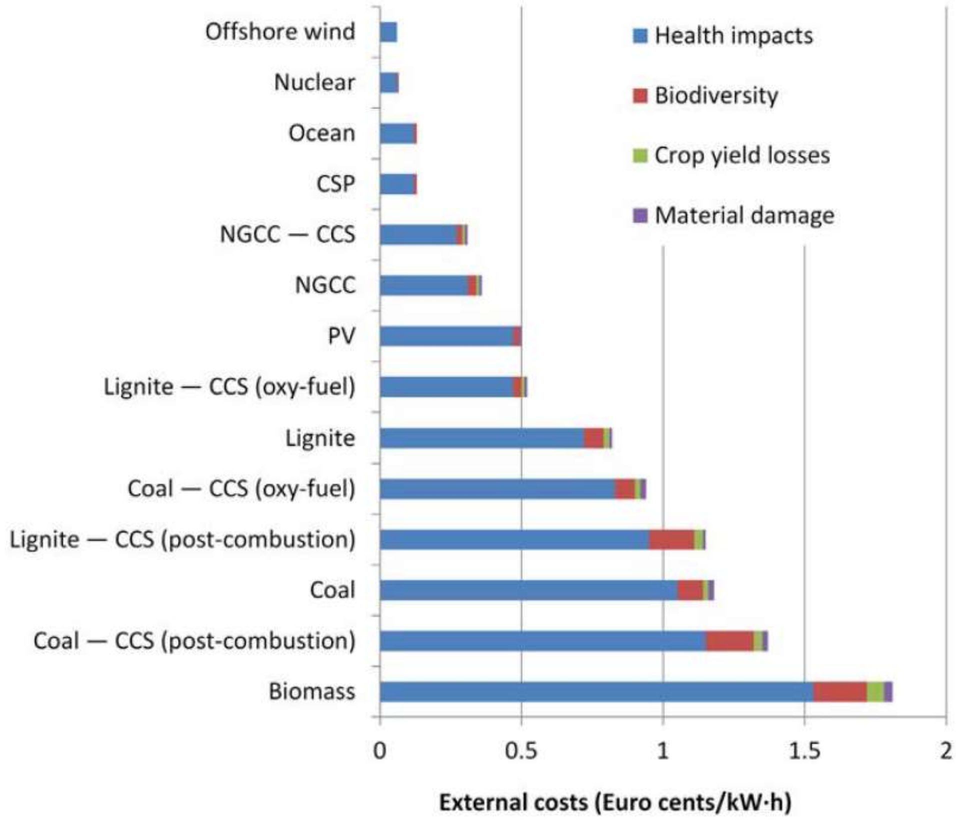

FIG. 23. External costs for electricity generation technologies (reproduced from Ref. [11]).

The IAEA has developed a simplified approach for estimating the environmental damage cost. The methodology is based on a very detailed study titled *Externe* and is embedded in the computer-based tool called SIMPACTS [12]. This tool allows quantification of the health and environmental impacts and external costs of different electricity generation technologies. It is particularly useful for comparative analyses of fossil, nuclear and renewable electricity generation. It can also be useful for evaluating cost effectiveness of environmental impacts mitigation options.

6.3. CLIMATE CHANGE MITIGATION COSTS

The energy sector is the main source of GHG emissions, and within the energy sector electricity generation is responsible for 25% of the global GHG emissions. As the present electricity generation in most of the countries is heavily based on fossil fuels, the climate policies are focused on moving away from fossil fuels-based electricity production. Nuclear power in this transition can play a major role as it does not emit GHG during electricity production and even on the life cycle basis, its emissions are negligible. Figure 37 compares GHG emission for different electricity generation technologies.

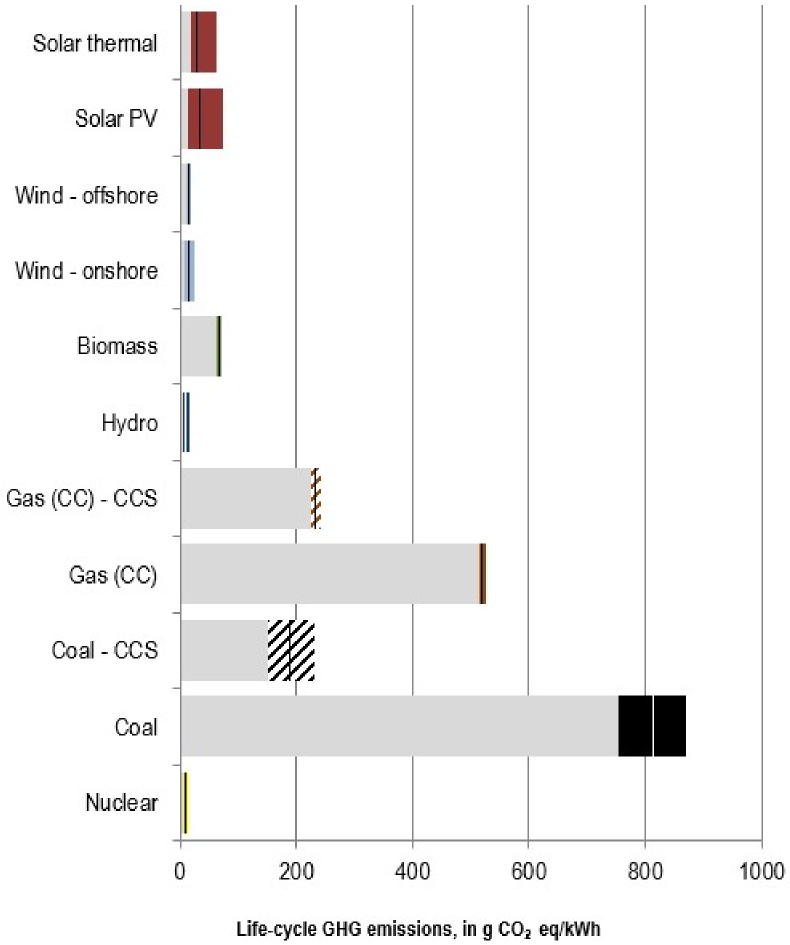

FIG. 24. GHG emissions from life cycle of different electricity generation technologies (reproduced from Ref. [13]).

All low-carbon electricity generation sources share a similar cost structure. They require high up-front investment but have low operating costs. Total electricity generation costs are thus mostly independent of the electricity output. Conversely, the cost structure of fossil fueled electricity technologies is characterized by relatively lower investments but a much higher share of operating costs, mainly fuel. The up-front high investments on low-carbon electricity generation technologies, in some cases, make them less competitive. However, if the carbon dioxide is priced and added in an economic comparison, the ranking of alternatives would change. A generic comparison of per unit electricity cost of nuclear power with fossil-based electricity generation is shown in Fig. 25. Here, two levels - low and high, for investment cost of nuclear power are compared with fossil-based electricity plants. If a carbon price of US $ 10 per tonne of CO_2 emissions is added to the generation cost of coal-based power plant, nuclear power becomes cheaper, assuming lower range of capital cost for nuclear plant. If US $ 20 tonne of CO_2 emissions is added, then nuclear becomes cheaper even for high end of capital cost range.

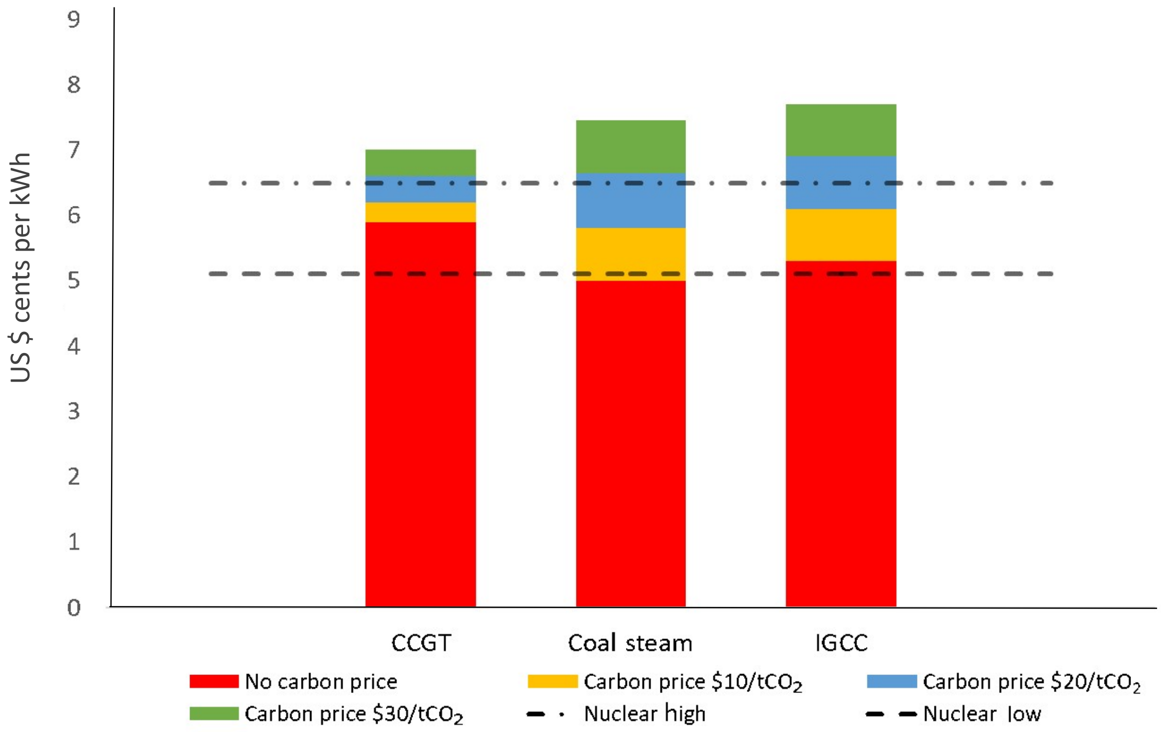

FIG. 25. Economic comparison of nuclear with fossil fueled power plants at different prices for carbon.

GHG abatement cost for different electricity generation technologies is shown in Fig. 26, based on data from Ref. [14]. Here the abatement cost is computed by accounting the GHG emissions avoided compared to a typical coal-fired power plant. Nuclear power offers a competitive option for GHG abatement.

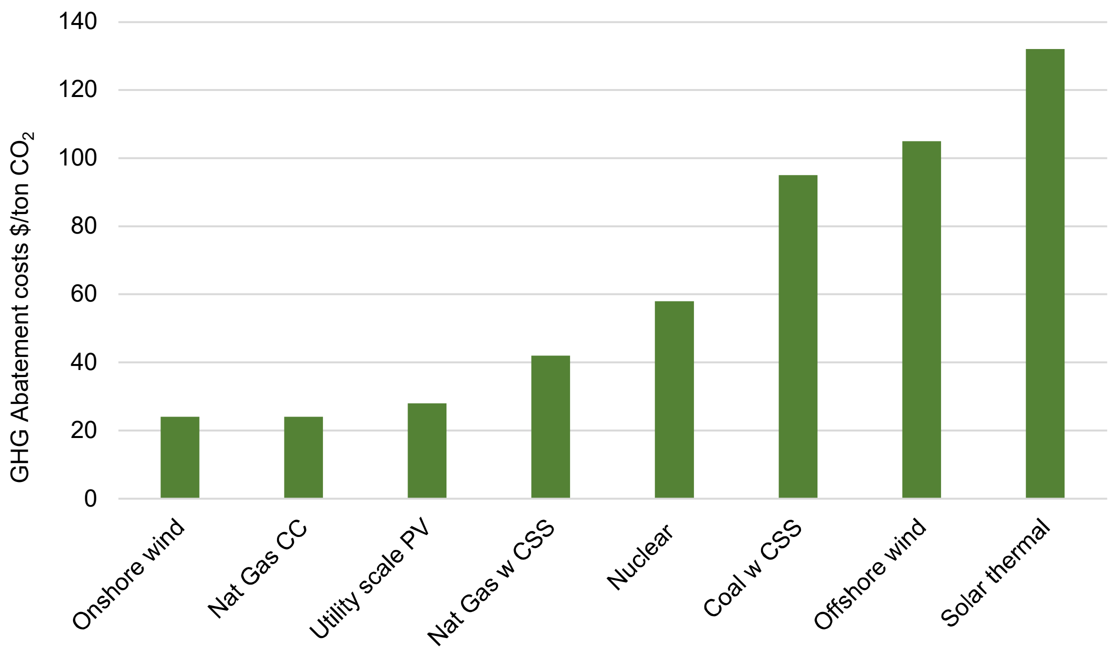

FIG. 26. GHG abatement cost for different electricity generation technologies.

Furthermore, capital intensity – investments required per unit CO_2 avoided, is another important indicator for comparing GHG abatement options. Figure 27 presents capital intensity of different electricity technologies for GHG avoidance. Nuclear power has the lowest capital intensity for GHG avoidance.

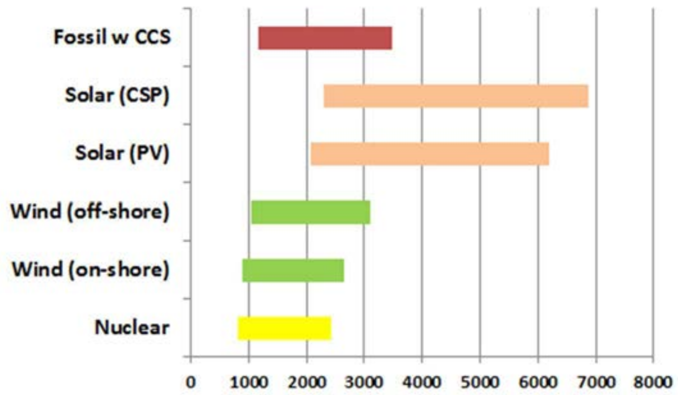

FIG. 27. Capital intensity of CO_2 avoidance (US \$ per ton of CO_2 avoided).

6.4. OTHER EXTERNAL COSTS

Wastes generated by various technologies are compared in Fig. 28. Coal-fired power plants produce the largest amounts of solid waste on per unit of electricity which contain hazardous heavy metals. Besides ash and sludge from coal combustion, the desulphurization process produces large amounts of solid waste. Oil-fired power plants, if fitted with flue gas desulphurization equipment, also produce large amounts of solid waste. In countries where environmental regulations are strictly enforced, the solid waste of coal and oil-fired plants is properly managed, and the corresponding cost is accounted for. In several other countries, waste from coal power generation is not yet classified as hazardous and not safely disposed of.

In case of nuclear power, the volume of the waste, particularly high-level waste and spent fuel, per unit of electricity generation are very small but their special characteristics – radioactivity – require careful management. Since the nuclear materials, including nuclear waste, are stringently regulated, appropriate arrangements are in place in each country for proper management of nuclear waste. The estimated costs for spent fuel management and disposal of radioactive wastes are already incorporated into the electricity generation cost of nuclear power plants.

Renewable energy technologies also produce some waste (Fig. 28) which are not large but could be toxic, e.g., toxic waste from solar PV. Managing and disposing of these wastes require significant expenditure which is not always reflected in the economic evaluation.

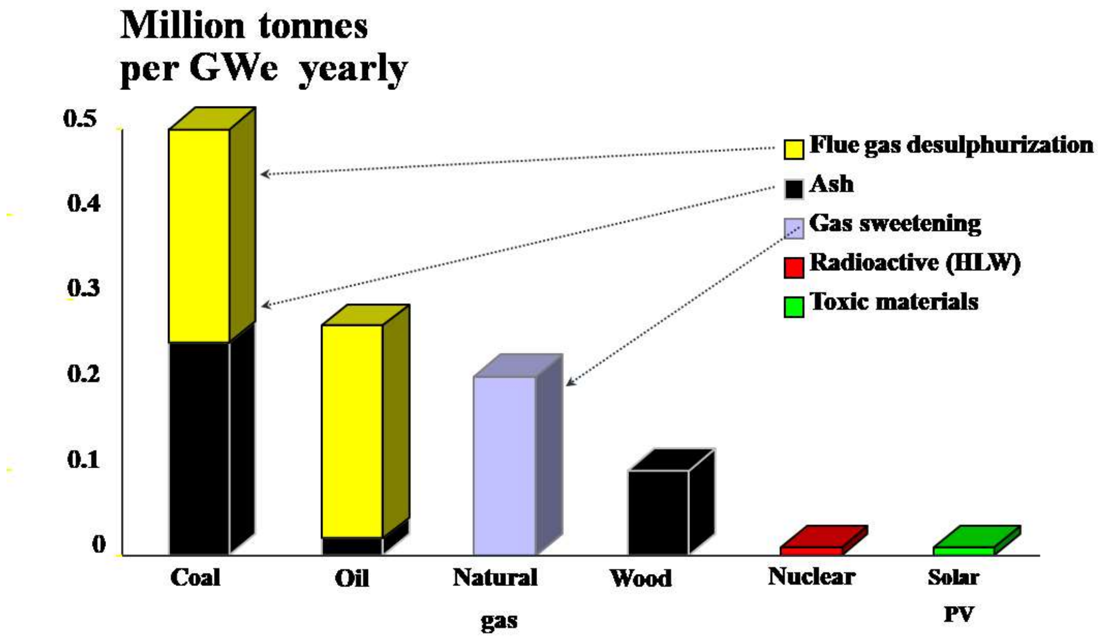

FIG. 28. Waste generated from different electricity generation technologies (reproduced from Ref. [15]).

In addition, there are several other environmental impacts which are not fully regulated or accounted for. These include adverse impacts on fresh water reservoirs, marine life, etc. (Fig. 29). Such negative impacts are not reflected in the economic comparison of alternative energy options.

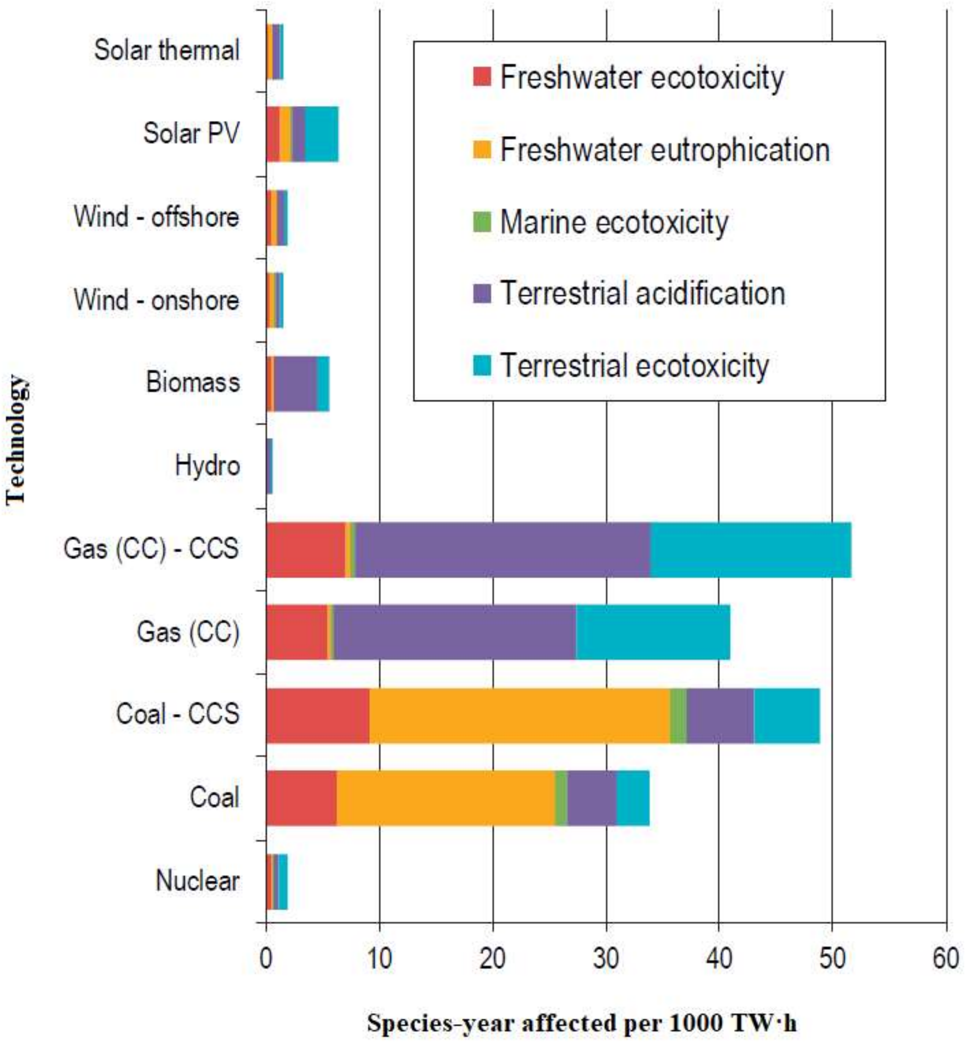

FIG. 29. Ecological impacts of electricity generation technologies in species-year affected per 1000 TW·h.; global average (reproduced from Ref. [13]).

7. MACRO-ECONOMIC IMPACTS OF NUCLEAR POWER

Energy is considered as the engine for economic development and social progress. Energy sector, however, is a capital-intensive sector and requires large investments for ensuring affordable, reliable and clean energy supplies. Nuclear power in particular is a very highly capital-intensive option, but it can offer several economic benefits to a country. However, it is imperative to assess whether or not a nuclear power project would be affordable for a country and the high investment for such a project can be arranged – as per the INPRO user requirements for the area of economics. This can be assessed by estimating the macro-economic impacts of a nuclear power project on a country's economy.

For assessment of nuclear power against its alternatives, it would be worth to consider estimating the potential economic impacts – both positive and negative, of introducing nuclear power. The main areas defining the status of an economy at the macro level are economic growth, employment level, general inflation, public debt, current account balance, external debt, etc. The desired trends for these indicators are shown in Table 16. The economic managers in a country monitor these indicators and introduce policies for correcting the course as deemed necessary. The investors also observe these indicators for assessing the health of the economy and making their investment decisions.

TABLE 16. MAIN MACRO ECONOMIC INDICATORS.

Macroeconomic indicator	Economic growth	Employment level	General inflation	Public debt	Current account	External debt
Desired direction	High	High	Low	Low	Surplus	Low

Depending upon a country's situation, the decision on investing in nuclear power can have positive macroeconomic impacts or cause significant burden for the economy.

7.1. IMPACT ON ECONOMIC GROWTH

A large-scale development project like a nuclear power plant can have significant impact of economic growth of a country, both from direct value added for such a large investment as well as from the ripple effect in other related sectors of the economy. For example, there could be a significant boost to the construction, manufacturing, services, etc., through cross-sectoral linkages thus generating additional economic growth. Furthermore, lower electricity price increases competitivity that stimulates further the GDP growth. However, such positive impacts would accrue if these activities are localized, i.e., provided by the local economy. A study on economic impacts of nuclear development in Republic of Korea, a country with very high localization of nuclear power plant, found that the Korean nuclear industry induced 2% increase in the GDP[16]. Other studies also found significant impact on economic growth due to nuclear power. For some countries, where nuclear power phase-out is being planned, it has been found that there would be about one percent drop in GDP together with a drop in employment [17].

On the other hand, the large investment on nuclear power project can swallow most of the investment capacity of the country, squeezing other sectors. This may retard the overall growth rate of the economy. This can be particularly an issue for small economies, as the nuclear investment in terms of gross domestic product can be very large. Additionally, there would be a net out-flow of capital to pay for the import of the nuclear plant and dependence on supplier country would increase. Furthermore, the positive impacts of a nuclear power project would start ensuing much later. Figure 30, based on data from the International Monetary Fund's World Economic Outlook[9], compares the size of a typical investment in a 2 x 1 GW nuclear power plant with the GDP of all countries, excluding G20. It can be noted that more than 40 countries have total GDP even smaller than the investments needed for a nuclear power project. These countries and several others cannot afford to invest in a nuclear project.

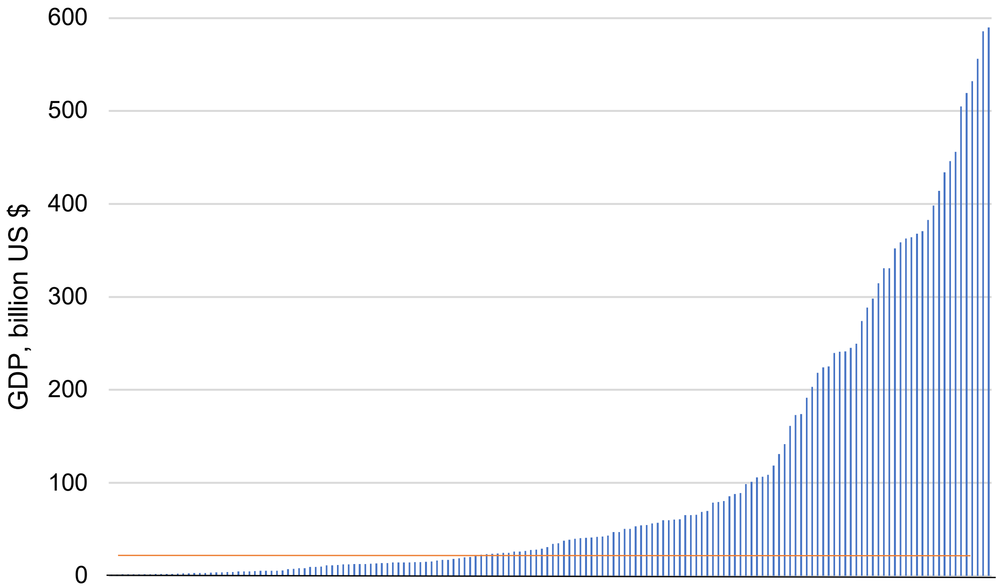

FIG. 30. Comparison of GDP of countries (not named here) with typical investment needed for a 2x1000 MW nuclear power project.

7.2. IMPACT ON EMPLOYMENT

Nuclear power industry creates high-skilled jobs. A large number of engineers and technical persons from a variety of disciplines are needed. Although, the nuclear industry is not a labor-intensive industry, it does have a significant impact on the status of employment in an economy. Table 17 compares different electricity generation technologies in terms of their employment creation.

Like any other economic activity, a nuclear power project creates direct as well as indirect jobs. The direct jobs are the person employed at a nuclear power plant during its various stages, while the indirect jobs are the employment at other industries and businesses involved in the supply-chain of products and services for the nuclear power plant.

[9]https://www.imf.org/external/datamapper/NGDPD@WEO/OEMDC/ADVEC/WEOWORLD/DZA

TABLE 17. COMPARISON OF EMPLOYMENT GENERATION BY DIFFERENT ELECTRICITY GENERATION OPTIONS.

Comparison of permanent direct local jobs per megawatt of installed electric capacity	
Technology	Jobs/MWe
PV	1.06
Nuclear	0.503 8
Concentrated solar power	0.47
Micro hydro<20 MW	0.45
Hydro>20MW	0.19
Coal	0.186 6
Hydro>500MW	0.113 7
Hydro pumped storage	0.095 4
Combined cycle	0.054 4
Wind	0.049

In addition to direct and indirect jobs, a large number of induced jobs are also created in the economy arising from the expenditures by direct and indirect employees on their personal needs, e.g., expenditure on food, clothing, housing, education, health, leisure, etc.

In terms of employment intensity, the entire life cycle of a nuclear power plant can be divided into four main periods: (i) construction period – 5 to 8 years, (ii) operation period – 40 to 60 years, (iii) decommissioning period – 8 to 10 years, and (iv) waste and spent nuclear fuel management period – 40 to 60 years. The highest number of jobs are created during the construction of a nuclear power plant. At peak of construction activity, the number of direct employments could reach 3500 persons. Several studies have been conducted to analyze the employment structure for a nuclear power plant. A recent study by NEA (2018) estimated that for a typical 1000 MW nuclear power plant [18]:

(i) About 12 000 person-years of labour is needed during construction phase of the plant.
(ii) Around 600 persons are required for operation and maintenance of the plant, and for providing administration and security services during the years of operation. This implies about 30 000 person-years of direct employment over the operation life.
(iii) Approximately 500 employees annually are required for decommissioning of the plant - equivalent to about 5000 person-years of direct employment.
(iv) And finally, about 80 persons are needed for managing storage of spent fuel and nuclear waste – equivalent to 3000 person-years of direct employment.

Altogether, about 50 000 person-years of direct employment are created over the entire life cycle of a nuclear power project. The NEA study estimated that from the supply-chain of such a plant, about 50 000 person-years of indirect employment will be created over the entire life cycle of the plant. This implies that a 1000 MW nuclear power plant would create 100 000 person -years of direct and indirect employment. If the entire life cycle of a nuclear power plant is considered as 100-years, it would create one job per MW of the capacity.
It has been estimated that nuclear industry in France employs 125 000 persons directly and about 114 000 persons indirectly. The induced jobs have been estimated at 171 000 persons. For South Korea, another country with well-developed nuclear sector, the employment has been estimated as 29 400 persons of direct jobs at nuclear power plants and about 36 700 persons in the supply-chain. Additionally, some 27 400 induced jobs are associated to nuclear sector.

It could be noted that the employment generation from a nuclear power plant in a developing country could be very different from the above estimates. A developing country would most likely import a nuclear power plant and its fuel and spare parts from an industrialized country. As such, in this case, the design, engineering and manufacturing jobs will be created in the supplier country. Furthermore, a large part of expertise for construction, project management, inspection/testing and other services would also come from the industrialized countries. Consequently, the local jobs creation could be more limited for a nuclear power project in a developing country.

The employment benefits of nuclear power need to be assessed in comparison with alternative options. Despite a significant number of jobs which could be created by a nuclear power project, the employment created by equivalent electricity capacity based on other energy sources, for example coal including mining, could be larger. As such, a more careful assessment of employment benefits of nuclear and its alternatives needs to be done under specific country conditions.

7.3. IMPACT ON INFLATION

As energy is needed for all economic activities, its prices influence the cost of production, transportation and delivery of all goods and services. Figure 31, based on data from the European Central Bank's Economic Bulletin[10], presents the weight of energy prices in the overall inflation in EU countries. It can be noted that for most EU countries, the energy prices accounted for about 50% of the total inflation.

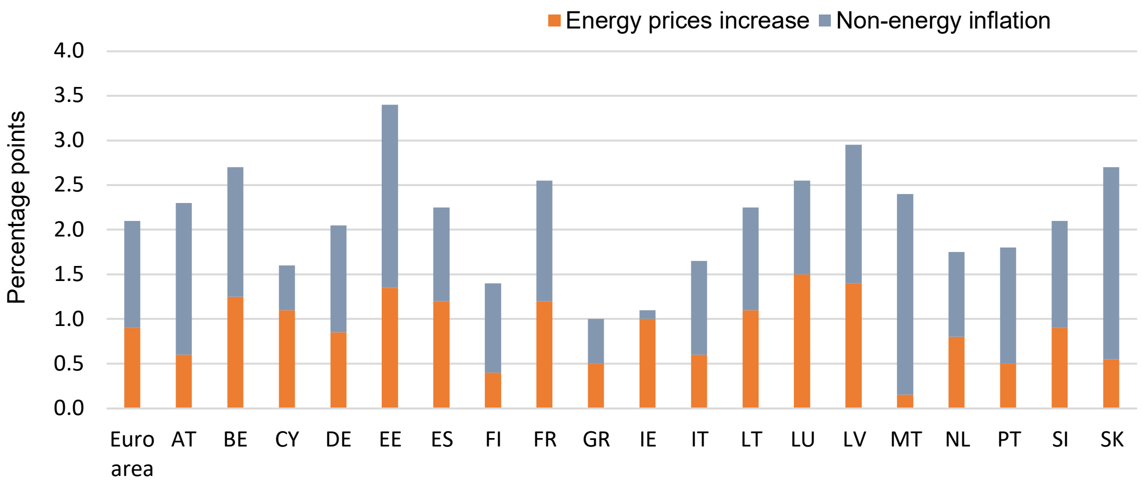

FIG. 31. Inflation versus energy prices in EU countries.

The higher contribution of energy in the overall inflation induces a considerable increase in general inflation whenever energy prices increase. For example, it has been observed in EU that energy prices and other items contributing to general inflation have been closely correlated as shown in Fig. 45, based on data from Ref. [19]. It can be noted that when energy prices were higher during the period 2011 to 2013, the prices of food and other items also increased with the result that the overall inflation also increased. Whereas, when the energy prices decreased during 2014 - 2016, the overall inflation also decreased significantly. And more recently, as the energy prices have increased again, the overall inflation has increased. It is therefore clear that if the energy and electricity prices are stable in a country, the overall inflation would be lower.

[10] https://www.ecb.europa.eu/pub/economic-bulletin/focus/2018/html/ecb.ebbox201807_05.en.html

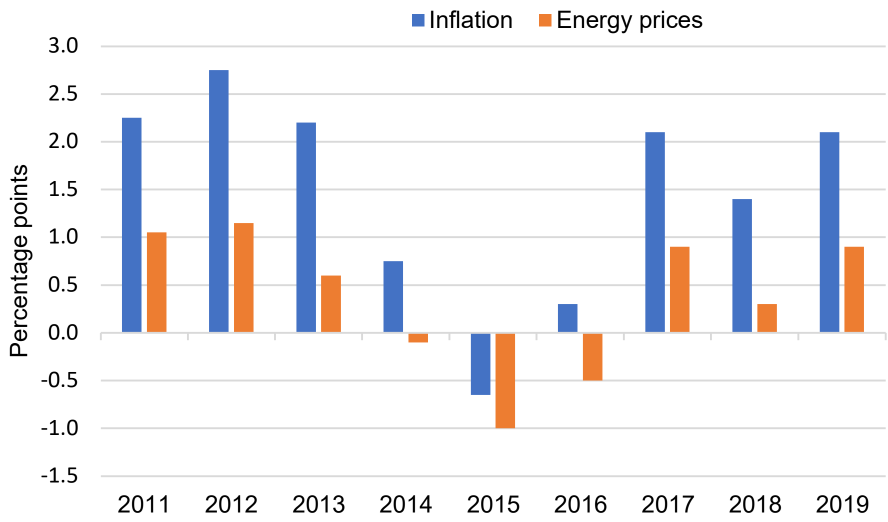

FIG. 32. Energy prices and inflation in EU.

The addition of a nuclear power plant in the energy supply mix of a country can help provide price stability for energy/electricity markets. Once a nuclear power plant is constructed, its electricity generation cost would remain stable, because major part of the nuclear generation cost coming from its investment is fixed while the operating costs, fuel and O&M, are relatively low. This provides price stability to electricity markets, which in turn would have a positive impact on the electricity consumers. For the industrial consumers, stable electricity prices would help them improve the competitiveness of their products, consequently resulting in a positive impact – reduced pressure, on general inflation in the country.

Many countries have as one of their economic management targets establishing price stability and containing inflation, because it helps boost the economic activities and growth in the country through (i) reducing real interest rates by lowering inflation risk premium, (ii) avoiding excessive hedging against the negative impact of inflation, (iii) contributing to financial stability and (iv) incentivizing new investments thereby generating employment. To pursue these objectives, the central banks intervene through various measures to establish price stability. The European Bank, for example, has established an upper limit of 2% inflation as its target and act accordingly to establish price stability in the Euro zone [19]. Nuclear power can help achieve price stability for electricity market in particular and in the overall economy in general.

7.4. IMPACT ON PUBLIC DEBT

If a nuclear power project is financed by the government, it may use its budgetary resources or/and borrow from local and/or foreign financial sources. In such a case, the investment on the nuclear power project would put a heavy burden leading to increase in public debt. Even if the nuclear power project is undertaken by a state-owned enterprise, which may borrow directly from local and/or foreign financial sources with the government guarantees, that type of borrowing is usually also counted towards public debt. In this case again, the investment on the nuclear project will increase the public indebtedness limiting the borrowing space of the government for other projects.

7.5. IMPACT ON CURRENT ACCOUNT BALANCE

A nuclear power project can significantly affect the external trade balance through the import or export of plant equipment and materials, fuel and spare parts, and technical services. For an industrial country exporting nuclear power plant, there would be a positive impact on its trade balance. The nuclear power industry in several countries have been using this argument in its favour for getting government's support. For an importing country, however, there would be a negative impact on external trade balance due to heavy outflow of funds for importing a nuclear power plant. In the case of a smaller economy, this could be very significant. A country which already has a large current account deficit would have serious difficulties in managing the external payments for a nuclear power project (the current account represents a country's foreign trade - a current account deficit arises in a country when the value of the goods and services it imports exceeds the value of goods and services it exports). Figure 33, based on data from the International Monetary Fund's World Economic Outlook[11], shows external trade balance of some countries. In some countries, the national financial management regulations establish a cap on the current account deficit. The European Union's requirement for its member countries is a maximum of 3% of GDP as the limit on current account deficit.

[11] https://www.imf.org/external/datamapper/datasets/WEO

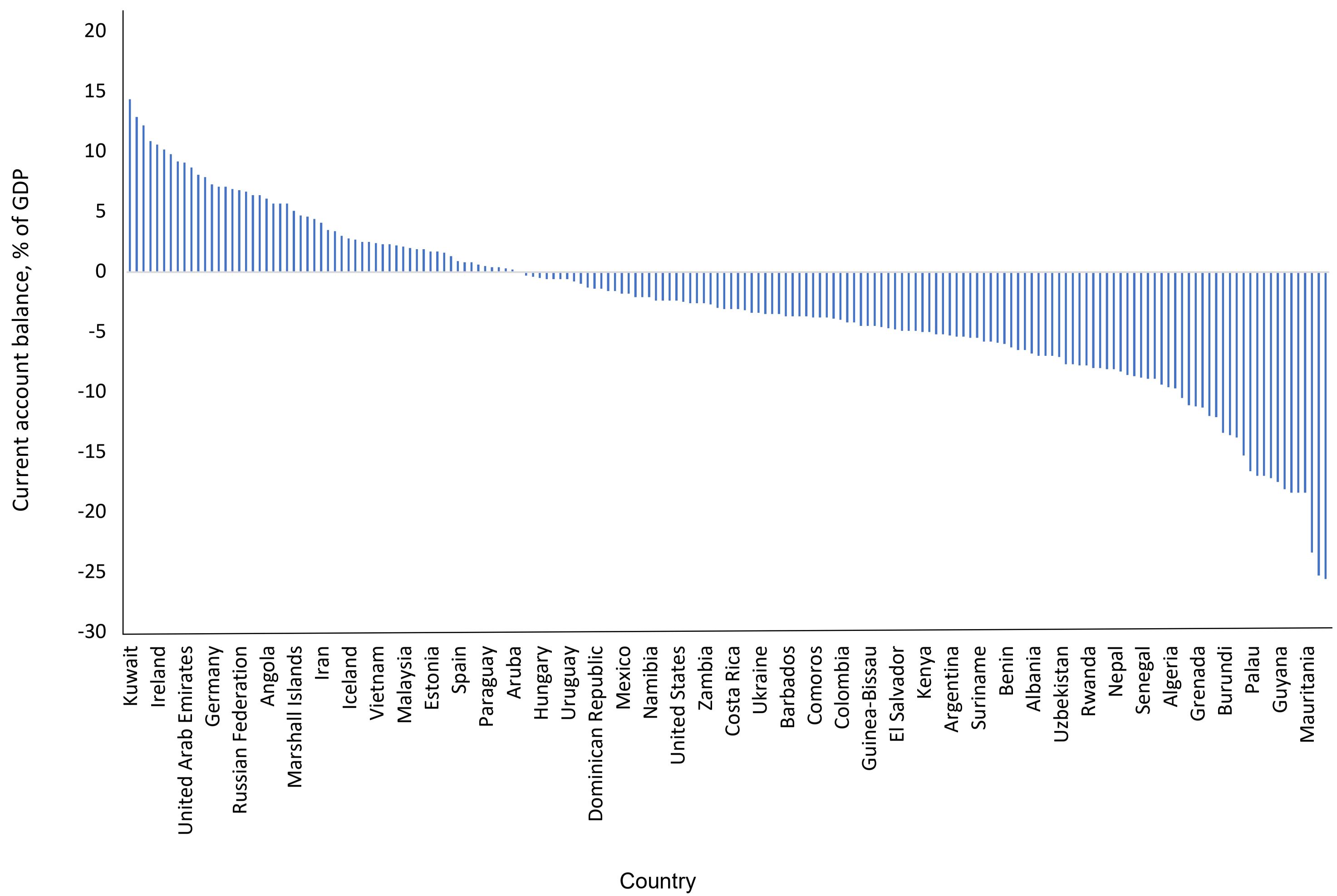

FIG. 33. Current account balance of selected countries.

The negative impact on external trade balance, however, could be offset in the long run by the reduction in import of the high-cost oil, gas or coal, if these are being imported by the country (even in case these fuels are exported by a country, the reduced local consumption may allow increased exports with a resultant positive impact on trade balance). Furthermore, since a large part of the capital investment on a nuclear power plant could be financed through long term credits, the negative impact on the balance of payment would be spread out over 12 - 18 years period, a country may be able to afford a capital-intensive nuclear power project. The overall impact on current account balance would be dependent on the specific economic condition of a country. As such, a detailed evaluation needs to be carried out to determine the impact of a nuclear power project on the current account balance of a country.

7.6. IMPACT ON EXTERNAL DEBT

Nuclear power projects in developing countries are usually financed through external loans. The lending entities would decide the loan based on several factors among which the creditworthiness of the borrower is an important factor. The creditworthiness is the ability of the borrower to pay back the loan. If a country is already committed to a large amount of previous loans, its ability to payback additional loan would be limited. Figure 34, based on data from the UN data Statistics library[12], shows external debt as percentage of Gross national income (GNI) for selected developing countries.

[12] http://data.un.org/Data.aspx?d=WDI&f=Indicator_Code%3ADT.DOD.DECT.GN.ZS

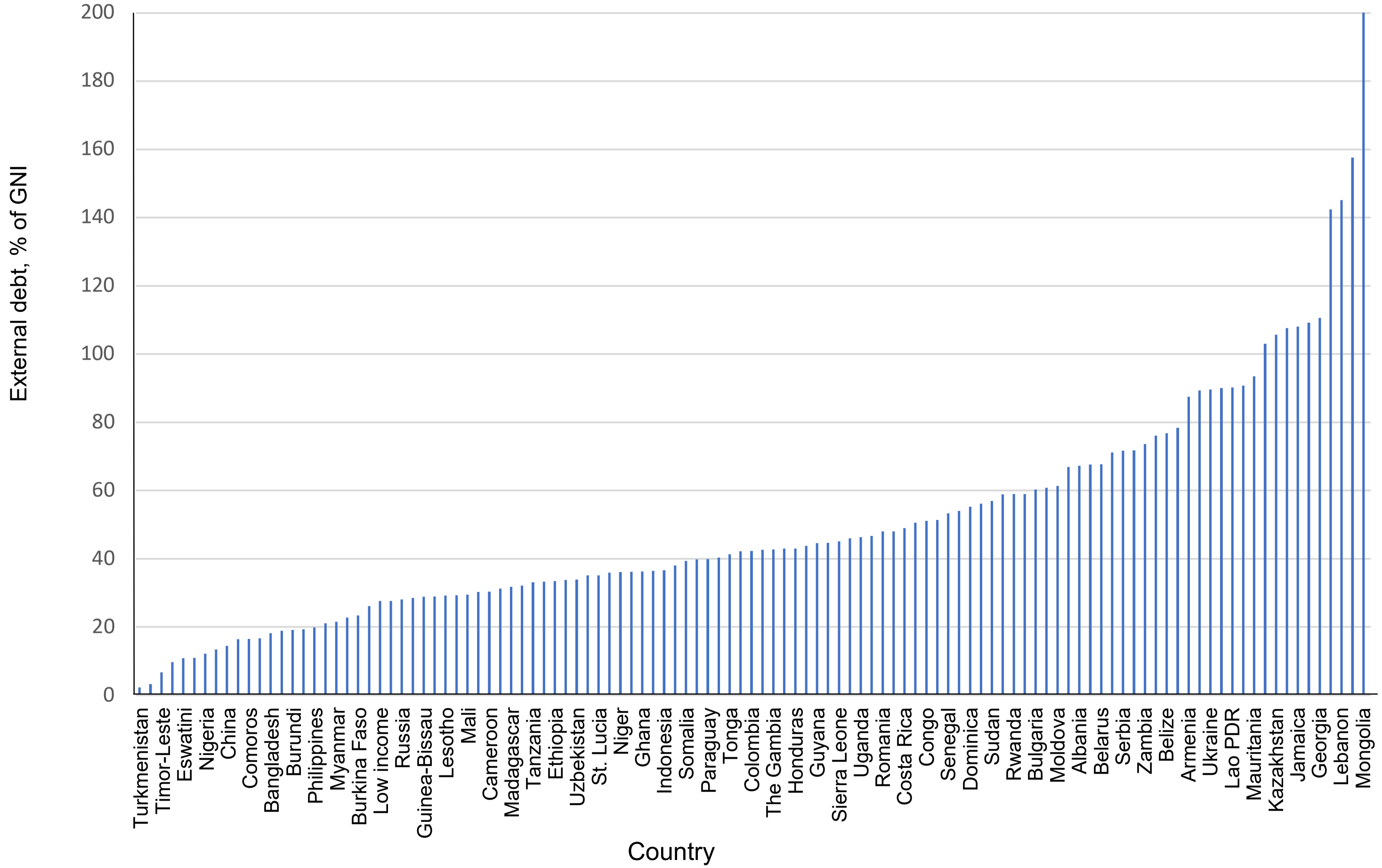

FIG. 34. Public Debt as percent of GDI for selected countries.

A nuclear power project, being highly capital intensive, would require large sums of borrowed funds, increasing the indebtedness of a country. For a sustainable management of national debt, the national regulations in some countries put a cap on government borrowing. In the EU, a 60% of GDP limit is prescribed to its member countries. The international institutions, e.g., IMF, also recommend a 60% of GDP as the maximum limit on public debt as a sustainable level. It may be noted that even if the national government itself is not directly borrowing, it could be required to provide sovereign guarantees for the loan for a nuclear power project in the country. Such commitments are also counted towards the creditworthiness of the countries.

8. APPLICATION LIMITS

The application limits of the presented approaches and formulas stem from the following facts:

- The expenditures to be made in a longer term in principle possess a high degree of uncertainty. For example, future robotization of the production processes might result in drastic reduction of the labour costs, while the costs of some materials might increase substantially owing to increased demand in other sectors of the industry.

- The time value of money concept implies any expenditures to be made in a short term are more important than those made in a longer term. With the discount rate included in all basic formulas presented in Sections 3 and 4, the results of any comparative evaluation of energy systems, technologies or scenarios will be dominated by short term rather than longer term expenditures.

- The fact that the time value of money concept diminishes or even nullifies the role of the expenditures to be made in a longer term, does not at all mean these expenditures would not be a burden for future generations[13].

All said above needs to be carefully taken into account when performing economic evaluations of nuclear energy system or scenario alternatives. The economic models work best for the projects or deployment scenarios that last for a decade or so, but will not per se produce meaningful results for, say, scenarios that involve deployments of the various technologies spread over several decades.

While there are no definitive solutions to overcome the topics mentioned above[14], the following broad advice on application of the presented in this publication economic models could be made:

(1) Comparing two nuclear energy systems with distinctly different properties and objectives, for example, comparing closed-cycle or partially closed-cycle systems with the once-through systems on purely economic indicators, would not lead to the meaningful results or conclusions.

(2) On the contrary, comparing the economic indicators for the alternative scenarios for "comparable" NESs could make sense. It is also true for comparing different individual projects within the proposed NES.

(3) Directly comparing economic indicators for the alternative scenarios of NES deployment without taking into account other features of these systems and the objectives they serve will make such evaluation rather limited.

(4) The projects implemented at different timesteps and aimed to serve the specific needs of a nuclear energy system (for example, fast breeder reactors) are not to be directly compared with other projects within the same NES based on just economic indicators

[13] Nuclear energy sustainability in INPRO is defined as "the ability to meet the needs of the present without compromising the ability of future generations to meet their own needs" [1].

[14] It is sometimes proposed to evaluate economic indicators for the expenditures to be made in a distant future as if these expenditures are made today (for example, see Section 4.6). While such evaluation may help skip the long term 'nullifying' effect of the discount rate, the huge uncertainty in costs in a long-term perspective will still remain a topic.

and criteria. However, an economic evaluation of the complete proposed NES can be performed.

9. CONCLUDING REMARKS

Economics is one of the main areas of the INPRO's methodology for the assessment of sustainability of nuclear energy systems. The economic evaluation of alternative nuclear energy systems involves not only the economic aspects but the special technical characteristics of nuclear power reactors and their fuel cycle. As described in this publication, the methodology for economic evaluation is based on standard economic concepts - such as, time value of money, amortization, depreciation, etc. - and the comparison among alternative is suggested to be made using standard metrics, like levelized unit energy cost, net present value, internal rate of return, etc.

It is evident that for a realistic economic comparison of alternatives, a plant level comparison is not adequate. The cost of grid extension and enhancement associated with the power plants needs to be included. Furthermore, since all the power plants in an electric system have to function in tandem and their true economic performance is heavily influenced by their operation in the system, the respective system cost effects are to be evaluated and included in the comparison. In some cases, the economic competitiveness of alternatives may change altogether once the system costs are included in the comparison.

Furthermore, it is now recognized that various electricity generation technologies cause severe environmental impacts resulting in considerable damages to human health and ecological systems. The cost of these damages could be internalized and included in the economic evaluation of alternatives.

This comprehensive economic evaluation would allow to judge the fulfilment of the INPRO user requirement which states that the cost of products from an NES is to be competitive with that of alternative energy sources.

Finally, the affordability of investment on a proposed nuclear energy system can be evaluated by assessing the macroeconomic impacts of the investment. This is particularly important for a developing country because most of the positive impacts, like highly paid jobs, manufacturing activity, etc., would be generated in the nuclear power plant supplier country, if the buyer country has limited expertise and industrial base. At the same time, import of nuclear plant would put a heavy burden on the economy in terms of current account balance and external debt. However, once the nuclear power plant starts commercial operation, it provides stability in electricity price and dampens the general inflation.

It is also important to recognize that the economic evaluation of a nuclear energy system would carry a number of uncertainties arising from assumptions on technical performance of the plant, construction cost estimates, prices of nuclear materials and fuel - cycle services, etc. Furthermore, if the environmental damage costs and carbon prices are taken into account, the uncertainties are compounded. As such, the results of economic comparison of alternatives are to be seen with care and used for ranking of the alternatives.

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ANNEX I

OVERVIEW OF THE INPRO METHODOLOGY IN THE AREA OF ECONOMICS

The INPRO Basic principle in the area of Economics reads as follows: ”Energy and related products and services from nuclear energy systems shall be affordable and available” [I-1].
The INPRO User requirements, Criteria, Indicators and Acceptance Limits are presented in Table I-1 below.

TABLE I-1. USER REQUIREMENTS, CRITERIA, INDICATORS AND ACCEPTANCE LIMITS OF THE INPRO METHODOLOGY [I-1]

User Requirement (UR)	Criterion	Indicator (IN) and acceptance limit (AL)
UR1: (Cost of energy): The cost of energy supplied by nuclear energy systems, taking all relevant costs and credits into account, CN, should be competitive with that of alternative energy sources, CA. that are available for a given application in the same time frame and geographic region/jurisdiction	CR1.1: Cost competitiveness	IN1.1: Cost of energy. AL1.1: CN < k*CA (CN = cost of nuclear energy, and CA = cost of energy from alternative source; factor k is usually > 1 and is based on strategic considerations)
UR2: (Ability to finance): The total investment required to design, construct, and commission nuclear energy systems, including interest during construction, should be such that the necessary investment funds can be raised	CR2.1: Attractiveness of investment	IN2.1: Financial figures of merit AL2.1: Figures of merit for investing in a NES are comparable with or better than those for competing energy technologies
	CR2.2: Investment limit	IN2.2: Total investment. AL2.2: The total investment required should be compatible with the ability to raise capital in a given market climate

TABLE I-1. USER REQUIREMENTS, CRITERIA, INDICATORS AND ACCEPTANCE LIMITS OF THE INPRO METHODOLOGY [I-1] (CONT.)

UR3: (Investment risk): The risk of investment in nuclear energy systems should be acceptable to investors	CR3.1: Maturity of design	IN3.1: Technical and regulatory status AL3.1: Technical development and status of licensing of a design to be installed or developed are sufficiently mature
	CR3.2: Construction schedule	IN3.2: Project construction and commissioning times used in economic evaluation AL3.2: Times for construction and commissioning used in economic evaluation are sufficiently accurate, i.e., realistic and not optimistic
	CR3.3: Uncertainty of economic input parameters	IN3.3: A sensitivity analysis of important input parameters for calculating costs and financial figures of merit has been performed AL3.3: Sensitivity to changes in selected parameters is acceptable to investor
	CR3.4: Political environment	IN3.4: Long term commitment to nuclear option AL3.4: Commitment sufficient to enable a return on investment
UR4: (Flexibility): Innovative nuclear energy systems should be compatible with meeting the requirements of different markets	CR4.1: Flexibility	IN4.1: Are the innovative NES components adaptable to different markets? AL4.1: Yes

REFERENCES TO ANNEX I

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ANNEX II

ECONOMIC COMPETITIVENESS OF SMR

II-1. SMALL MODULAR REACTORS (SMR): DEFINITION AND CURRENT STATUS

Small modular reactors (SMRs) are a new emerging nuclear power technology. This technology family is significantly distinct from the large light-water reactors (LWRs) that are the cornerstone of nuclear power in the modern economy. According to the definition used by the IAEA [II-1], SMRs are the advanced reactor designs that could be produced predominantly at dedicated factories with components (modules) transported to the installation sites (modularity concept). SMRs have capacity of up to 300 MW(e) per unit with an option to install additional units at the site depending on changes in the demand. SMRs are expected to be the next generation nuclear technology with advanced safety features integrated in the reactor designs.

There is no specific limitation on the type of technology used in the small reactors. Based on the currently proposed designs SMRs could be water cooled, high-temperature gas-cooled (HTGR), molten salt reactors (MSR) and fast reactors. Majority of the existing SMR designs are land-based, however, marine-based designs exist as well with the first SMR in commercial operation (since May 2020) being the floating nuclear power plant Akademik Lomonosov in Russia. A separate sub-category of this nuclear technology family are the microreactors. Their capacity is yet lower than the one of the SMRs being in 1-20 MW(e) range. The significant difference of microreactors from the SMRs is that majority of proposed designs are portable (ideally in the truck-size vehicle).

The interest to SMR technology due to its potential benefits is increasing in the IAEA Member States with multiple reactors designs currently being at different stages of development. In addition to the first floating SMR (using water-cooled technology), the HTR-PM in China is in operation since 20.12.2021[15] and a land-based water-cooled CAREM reactor in Argentina is at advanced stage of construction. Currently there are 18 countries with active SMR technology development programmes. A few IAEA Member States, e.g., the U.S., Russia and China have multiple SMR designs under development.

Over 60 SMR and 8 microreactor designs have been proposed globally [II-2]. Majority of them, however, are at very early stages of development and most probably only a few most successful concepts will go beyond the design phase. Considering current construction plans for different SMR designs in optimistic scenario by 2030 the total installed capacity of SMRs would be at the level of 1.6 GW(e), i.e., approximately equal to one unit of the largest conventional LWR reactor (of EPR type) currently being in operation [II-2]. Broader expansion of technology could be expected in 2030s if the prototypes to be built in 2020s will prove to be successful. Specifically, the high-case scenario proposed by the NEA projects over 20 GW(e) of installed SMR capacity by 2035 [II-3].

This Annex provides the overview of some most important factors affecting the economic competitiveness of SMRs. However, given the emerging character of SMR technology the empirical evidence is very limited. The actual impacts (both positive and negative) of factors to be discussed in further sections are hard to be quantified due to significant uncertainties associated with technology itself and with potential market conditions. Therefore, any existing estimates and projections related to SMR technology should be considered with caution.

https://pris.iaea.org/PRIS/CountryStatistics/CountryDetails.aspx?current=CN

II-2. CONSTRUCTION COSTS AND TIME

Important distinction of the SMR and large LWR technology families are the differences in upfront capital costs. As per definition, SMR units have capacity under 300 MW(e) per module, i.e. SMR modules will have capacity an order of magnitude lower that the conventional 1000 + MW(e) large LWRs. The implication of this difference is that construction costs should be significantly lower for SMRs due to the smaller scale of the project that decreases the amount of workforce, equipment and materials needed for the construction. Additionally, in many SMR designs the number of components, systems and structures is reduced due to the greater design integration. The amount of on-site construction work usually being one of the main sources of construction cost overruns and delays is smaller for SMRs than for large LWRs. This is applicable even for the prototype SMR units that will be constructed using more traditional construction techniques and involve less mass-produced factory-fabricated components.

Another important factor is the duration of SMR projects. The current expectation is that construction time of the SMR could be reduced to 3 - 4 years in comparison with 5 - 8 years for typical large LWR unit. This reduction could, however, be achieved only when the technology would reach maturity. Current prototype SMRs have much longer construction times: the works on HTR-PM in China and on CAREM in Argentina started in 2012 and 2014 respectively. HTR-PM was commissioned and started operation on 20.12.2021, but CAREM is still not commissioned though is at advanced stage of construction. Manufacturing of the only currently operational SMR (floating NPP “Akademik Lomonosov” in Russia) started in 2007 with the beginning of commercial operation in 2020[16].

Due to the lack of empirical data developing reliable estimates of the SMR unit construction costs is currently not possible. Therefore, any actual comparisons with large LWRs are highly theoretical and assumptive. Moreover, the costs of SMR units could vary in a broad range depending on the type of technology used in the SMR (e.g., traditional light water-cooling against more futuristic Generation-IV type technologies) and reactor capacity. Given the large number of designs currently being under discussion, the actual construction and operation experience for prototypes would probably be the only way to determine the most promising designs for deployment at a larger scale.

In principle, for SMRs to become competitive with LWRs at open markets their investment costs per MW(e) of installed capacity should be at the same level or lower. This is an unrealistic assumption for the prototype reactors to be constructed with the primary goal to prove the viability of specific technology and design in 2020s. However, according to the NEA estimates, in case of mass production (which could be foreseen not earlier than in 2030s) due to the optimization of supply chains (reduced number of subcontractors) and introduction of advanced construction techniques, including factory production, the SMR investment costs could be significantly reduced [II-3].

An example of the cost estimate for the perspective SMR design are the calculations made by the NEA for SMART small reactor developed by the Korean Atomic Energy Research Institute (KAERI). The approach is based on deriving analogy with the overnight costs of large light-water reactor design APR-1400 also developed in Korea. Based on the NEA scaling function and considering contingencies (cost-increasing factor) and advanced construction methods (cost-decreasing factor - assumed to save 10% of construction costs) the estimate of total overnight costs is USD 525 million or USD 5250/kW(e) considering that nameplate electricity generation capacity of SMART is 100 MW(e) [II-3]. These numbers are the ‘target’ estimate -

[16] https://pris.iaea.org/PRIS/CountryStatistics/ReactorDetails.aspx?current=895

basically the best-case scenario valid for mass-produced SMR with advanced construction techniques including factory production in place. The common economic approach on how the progress towards these cost-reduction targets could be reached is discussed in the section below.

II-3. LEARNING CURVES AND COST REDUCTIONS

The SMR designs currently being constructed and planned are the first-of-a-kind (FOAK) ones. Due to the innovative nature of technology and lack of construction experience for SMRs their construction costs will likely be very high (similarly to innovative large LWRs). After the reference FOAK reactor of certain design will be constructed, the subsequent units (Nth-of-a-kind – NOAK) will be able to benefit from the lessons learnt and from optimizations implemented based on the construction and operation of the FOAK reactor. The process of gradual cost decrease for each consecutively constructed reactor achieved through learning, optimization of processes and use of advanced construction techniques is called the learning curve.

Significant difference between the costs of FOAK and NOAK reactors is not unexpected and impacts of learning on the historic costs of reactor construction have been studied extensively [II-4]. However, the difference between the FOAK and NOAK SMRs could be more significant than for conventional LWRs. First prototypical SMRs would be constructed using similar approach as the conventional LWRs with most of the works being done on the construction side. The paradigm change can really occur for mass construction of SMRs when the factories producing building blocks (modules) for SMRs would be constructed (modularity is discussed in the section below). Factory production and standardization could potentially become a critical driver of cost reduction between the FOAK and NOAK SMRs. Conventional large LWRs historically enjoyed limited benefits from standardization. Specifically, one of the main reasons identified for negative learning (cost increases for construction of subsequent reactors of similar type) is that there was a constant evolution of reactor designs and majority of the nuclear power projects, particularly in the USA, had important distinctions. The lessons learned from one project were not applied to the other projects because of different designs and site-specific variations.

Cost estimates for many nuclear power projects (conventional large LWRs, large Generation-IV reactors and prospective SMR designs) implicitly use the assumption that the whole construction process goes according to the plan with minimal cost overruns and delays. This is an unrealistic assumption for the FOAK projects and therefore such estimates should be interpreted as the target values for the NOAK reactors [II-5]. In case of SMRs best-case scenario assumptions would not be realistic even for the so-called post-FOAK units, i.e., the first factory-manufactured SMRs [II-6], that would follow the prototype FOAK SMRs constructed predominantly on-site.

For reference, the capital costs of a FOAK small reactor project (with a total 440 - 600 MW(e) capacity) in the publication of Expert finance working group on Small nuclear reactors of the UK government are estimated at the level £2 - 2.5 billion (USD 2.7 - 3.4 billion) against £20 billion (USD 27 billion) for a large LWR project [II-6]. The numbers are specific to the UK and, considering the proposed costs for the large LWR project, are generally on the upper side of the spectrum. However, the takeaway from this estimate is that the costs of the SMR project are expected to be an order of magnitude lower than of the conventional LWR. Moreover, it is assumed in the publication that very significant cost savings are possible for the NOAK small reactor projects – up to £1 - 1.5 billion.

The study conducted by Ernst & Young (EY) within the framework of an independent Techno-economic assessment (TEA) of SMRs initiated by the UK government provides another optimistic estimate of learning curve for the SMRs. According to the EY analysis, serial SMR manufacturing could reduce costs at 8% learning rate for each cumulative doubling of their factory production. More specifically, CAPEX reductions are expected to be within 5 - 10% range [II-7].

II-4. MODULARIZATION AND MASS PRODUCTION

Generally optimistic expectations about the learning curve for the SMRs are heavily dependent on the increasing role of factory production for manufacturing of SMR components (modules). After production these modules will be delivered to the construction site and installed there with minimal amount of work being done on-site. The whole process is called modularization. According to the formal definition proposed by the NEA '*Modularization is the process of breaking a large and complicated product down into smaller building blocks, or modules, according to a set of limited constraints'* [II-3]. The benefit of this process and the reason why it is seen as a potential game-changer for the SMR technology is that factory production is more predictable and controllable. The components produced at factory get the benefits of mass production with significantly more efficient quality control (faulty components and mistakes made during construction caused cost overruns and significant delays for the NPP projects over the last decades) and higher overall productivity. Probability gains are achieved by breaking operations into smaller and simpler ones with lower probability of making a mistake, and by reducing the number of interfaces between different components (in comparison with on-site works).

Factory production and modularization are not unique for the SMRs and have been used for contemporary large LWRs as well. For current LWR designs up to 30% of construction costs are associated with the factory produced components [II-7]. What is different for the SMRs, however, is that much higher level of factory production is potentially possible (60 - 80%). The role of modularization is limited for the large LWRs by the size of their components as their transportation becomes prohibitively expensive or impossible with the use of standard transport vehicles. For the reactors with the power capacity under 500 MW(e) the degree of modularization significantly increases. Very high levels of modularization for the SMRs (60 - 80% cited before) could be achieved through 'aggressive' strategies, i.e., further subdivision of modules for greater transportability [II-8]. In principle, if such level of modularization would be achieved, SMRs would become mostly factory-manufactured products with limited accompanying installation works being done on-site. This would be a major difference with large LWR projects that would predominantly remain constructed in a conventional way with some components being factory produced. The scale of impact caused by shifting to standardized factory production on the high-tech industry could historically be observed with aircraft manufacturing.

These estimates of potential modularization levels are, however, theoretical as no SMR factory has been constructed yet. All current or near-future SMR projects are the prototypes and will still be constructed in a conventional way. In optimistic scenario after construction of prototypes and based on experience of their exploitation the most promising designs will be chosen given the sufficient market demand. Following this the factories for manufacturing of successful SMR designs could be designed and constructed. Development of SMR factories will be a challenging task by itself. The non-prototype SMRs will be constructed only after this with the actual impacts of learning curve and modularity becoming clear significantly later.

All previously proposed estimates imply mass production of SMRs, which means that significant market should become available by the time of factory construction. Specifically, the Ernst & Young study estimates that cost parity (based on LCOE) with conventional NOAK large reactor could be achieved after deployment of 5 GW(e) SMR capacity with factory production of 10 units per year [II-7]. For the SMR design with 100 MW(e) capacity this means that over 50 units will need to be constructed before SMRs will become competitive with large reactors. Moreover, these are not 50 units produced in total at the whole market globally but 50 units of only one SMR design that will be competing not only with large LWRs but also with other SMRs. Within the framework of this model all these 50 original units will be produced at costs higher than conventional LWRs (per MW(e) of installed capacity).

To make this viable even at larger national markets significant government participation will be needed. Specifically, the first recommendation of the Expert Finance Working Group on Small Nuclear Reactors is that the UK government '*Should enable the small nuclear sector through a clear Policy and a market framework, rather than down-selecting technologies*' [II-6]. Development of such policy instruments and frameworks is yet to happen in future. Additionally, the production volume of SMRs will need to be supported over time to keep the supply chains functional and secure operation of the SMR factories. The examples of shutting down highly expensive projects where demand was not sufficient to keep production alive could be found in high-tech industries relying on mass production, specifically, in aviation. The most recent case is the largest passenger aircraft Airbus A380 (once seen as the future of aviation) that was in 2021. Very careful market studies will be needed for factory produced SMR designs in 2030s to avoid overestimation of demand and to develop viable contingency strategies.

II-5. MULTIPLE-UNIT SMR PLANTS

The concept related to mass production and modularity of SMRs is the construction of nuclear power plants (NPPs) with multiple SMR units. This approach is not novel for the nuclear industry as conventional NPPs are commonly constructed with multiple units at the same site (most often two or four nuclear power reactors). Additional reactor units are added as the demand increases or older units get retired. The rational for this is that the NPPs with multiple units share the infrastructure that allows decreasing the overall cost of the project. Similar logic is applicable to the SMRs. According to the Ernst & Young estimates, capital costs' savings of 5% per reactor could be achieved for the NPP with 2 SMR units, and up to 14% for the NPP with 12 SMR units [II-7].

The specificity of SMRs is that significantly higher number of modules could potentially be installed at one site and generally higher flexibility with adding more reactor units could be expected. Additional factory-produced units could be installed at the SMR power plant site faster considering that necessary infrastructure was already developed for the previously installed units. In case of highly advanced modularization the amount of on-site works for the subsequent reactor units would be minimal. The SMR power plants can be more flexible in terms of addressing the changes in the electricity demand: additional large LWR unit means extra 1000+ MW(e) capacity while SMR modules allow more gradual increases in the power plant capacity.

Significant benefit of having a few SMRs instead of one LWR, especially in smaller grids, where one NPP could stand for significant share of national demand, is the minimized outage times due to maintenance and refueling [II-3]. The reason is that servicing of SMRs could be done on a unit-by-unit basis and not all capacity of NPP with multiple SMRs would be deducted from the grid at the same time. In case if the large LWR is being refueled over 1000 MW(e) capacity would not be available to the electricity system and will need to be covered either by backup capacity or by imports of energy from abroad. Keeping extra 1000 MW(e) backup capacity only to cover for the maintenance and refueling of the nuclear power reactor for the smaller grids could be economically unviable. However, the NPP of similar capacity (1000 MW(e)) but consisting of 10 SMR units with 100 MW(e) capacity each would require only 100 MW(e) of backup to cover for planned maintenance and refueling, i.e., an order of magnitude less.

Additionally, SMRs are expected to have minimal outage times for each reactor unit in comparison with large LWRs due to the specifics of their design. Specifically, the average outage time for RITM-200 (Russia) is estimated to be 5.2% - 460 outage hours per year (1 year equals 8760 hours). The first outage for this design is expected 3 years after the beginning of operation (for 10 days) and the first major outage (for 150 days) 20 years after the beginning of operation [II-9]. Holtec SMR design, as cited by the NEA, is expected to need refueling (lasting one week) only once every 42 months [II-9].

The scale of potential benefits of NPPs with multiple SMR units, however, is more on the theoretical side and hard to be quantified. Development of the SMR plants reserving an option to install additional units at the same site depending on potential future changes in the electricity demand could be problematic either. The number of sites suitable for the NPPs is usually limited and the benefit of SMR is often seen in its smaller physical size as it makes more sites suitable for the NPP construction. Allocation of a larger site for the SMR project could therefore become problematic: the place where the large LWR could have been constructed would be occupied but with much less capacity installed. Additionally, the costs of infrastructure development are largely fixed and need to be paid upfront making the first SMR unit expensive if multiple other units are not constructed at the same time.

Another argument used in favor of gradual additions of SMR capacity at the same NPP site is that the revenue generated by one reactor could be used for the construction of the consequent ones. This is a clear oversimplification as the power plants do not operate in an isolated manner and normally belong to a larger utility that redistributes revenues across all projects – from this point of view construction of additional unit at the same site is not different from its construction elsewhere.

II-6. DISECONOMIES OF SCALE OR LOST ECONOMIES OF SCALE?

The factors affecting economic competitiveness of SMRs discussed in previous sections are focusing on their potential benefits in comparison with large LWRs. As mentioned before, these benefits are often hard to quantify at this stage and many of them can only be unfolded when technology would be mature enough (the stage of mass factory production of SMRs), however they are still mostly favorable to the SMR technology.

The main argument used against the economic competitiveness of SMRs is based on the concept of *economies of scale*. Economies of scale are the cost advantages achieved through the increased amount of output. In this case the costs per unit decrease as the output increases. The reasons for this could be multiple, including the division of fixed costs that do not vary for the enterprise or facility between more units of output or physical and engineering factors, e.g. the square-cube law based on the fact that the surface of the unit increases by the square but the volume increases by the cube (common for construction of buildings, ships and aircraft). The opposite trend, when the costs per unit increase as production increases is called diseconomies of scale. This could be caused by increasing complexity of management and coordination for large volume production.

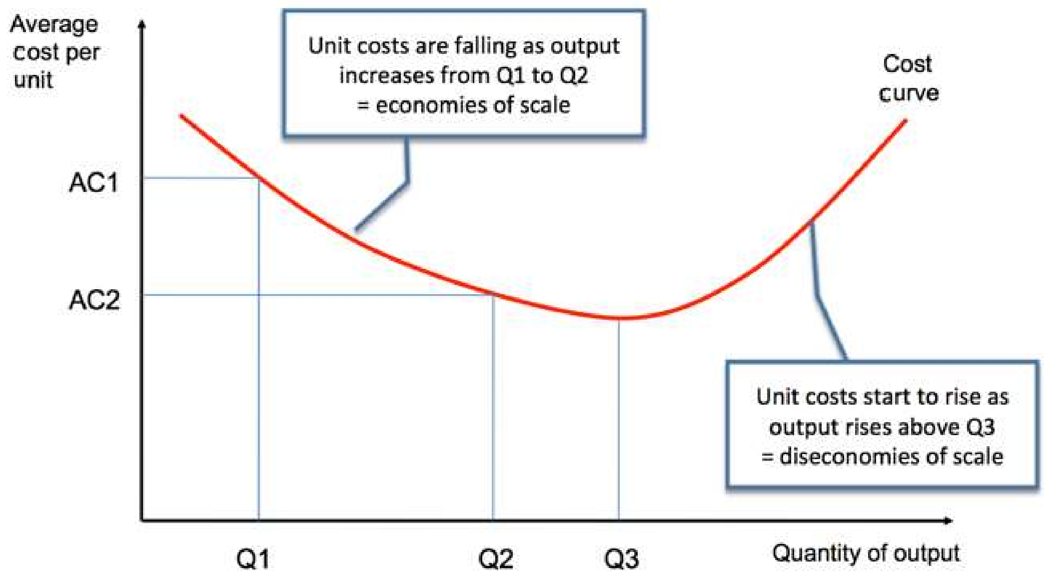

FIG II-1. Typical relation between average cost of production and volume of production.

Economies of scale were broadly used in the nuclear industry as the argument in favor of constantly increasing the capacity of nuclear power reactors to reduce the costs per MW(e) of installed capacity. Indeed, the first reactors had a capacity of a few hundred MW(e), while current designs of large LWRs are usually over 1000 MW(e). The motivation for this drive over decades was clear: (i) construction of NPP includes significant amount of fixed costs or costs that do not increase proportionally to its capacity (therefore capital costs per MW(e) of installed capacity could be decreased), and (ii) the number of employees does not increase proportionally to the size of the NPP and thus operational costs could be reduced over the lifetime of the NPP.

Within the framework of this logic SMRs obviously lose the benefits of economies of scale obtained by the industry through the increase of reactor capacity. However, similarly to the positive arguments in favor of SMRs used in previous sections, the reality for the negative argument is also more complex. First of all, the evidence with the economies of scale for large LWRs is ambiguous: the units with 1000 MW(e) capacity were developed already in 1970s and over the last 40 years the capacity increases of large LWR designs was limited with contemporary ones being mostly in the range 1100 - 1300 MW(e). The only significantly larger design that was constructed is the EPR with 1660 MW(e) nameplate capacity[17]. The evidence on cost reductions in nuclear industry over time for which economies of scale should have been one of the factors is very mixed as well [II-4]. Obviously, the costs of NPP construction were affected by multiple factors (e.g., increased safety regulations over the last decades), however, existing evidence shows that even if large nuclear did not get to the 'diseconomies of scale' part of the cost curve, economies of scale probably were not the dominating factor in determining the costs of nuclear.

The loss of economies of scale *by size* effect (by reduced installed capacity) could push the costs of SMRs (per unit of output) upwards, however, the scale of this cost increase is hard to be quantified. On the opposite side, mass factory production of SMRs could potentially lead to economies of scale *by volume* that are not achievable for large LWRs. Potentially this is the greatest difference between mass-produced factory goods and unique projects constructed predominantly on-site. According to the REDCOST study [II-8], the effect associated with the loss of economies of scale for the SMRs could be potentially compensated by (i) modularization

[17] https://pris.iaea.org/PRIS/CountryStatistics/CountryDetails.aspx?current=FI

and factory build, (ii) design simplification, (iii) standardization, and (iv) harmonization. These factors could obviously benefit large LWRs as well, however, as discussed in previous sections their impacts are limited by technological, logistical and market reasons. The economic competitiveness of SMRs with LWRs would strongly depend on actual impacts of these and other factors driving costs upwards and downwards, including regulatory requirements, public acceptance, and national market conditions.

II-7. SMR FINANCING: SOURCES AND IMPACTS ON COSTS OF CAPITAL

Discussion on the milestones at the path towards creation of mass SMR market including the development of safety regulations, construction of prototype SMR for technology demonstration, establishment of the SMR factory, manufacturing of first factory produced SMR, and gradual cost decrease through the economies of scale by volume for NOAK SMRs provides an impressive vision of future for industry spreading over decades. However, the implementation of these steps would fundamentally depend on two factors: market demand and access to capital.

As discussed in previous sections, SMRs would offer rather distinct value proposition differentiating them from large LWRs and thus potentially affecting their access to financing. However, SMRs are still nuclear power plants and therefore similarities with existing financing schemes would be significant. The first SMRs to be constructed will be the prototypes, which means that economic competitiveness of these initial units will not be the primary factor affecting the investment decision. According to the Expert finance working group on Small nuclear reactors of the UK government the costs of FOAK SMRs could be twice higher than NOAK units [II-6]. Implementation of FOAK projects will therefore in many cases need certain level of government support. In principle such support is common for emerging technologies. The degree of support and the types of government incentives (direct or indirect) would depend on the type of the market (regulated or liberalized) where the prototype SMR would be constructed. The difference would also depend on the type of vendor: large established nuclear company with proven track-record in developing nuclear technology (e.g., conventional LWRs) and significant resources available would be in a different position than the SMR startup promoting its first nuclear reactor design.

Important incentives, especially in liberalized markets, would be of institutional nature, specifically different policies and market frameworks, including clarifications for the risk allocations that could be the barriers for the SMR projects, especially those using advanced Generation-IV technologies. Associated factor would be the government role in regulatory process and approval, including safety requirements for the SMRs. Government guarantees and seed financing of promising SMR projects could be critical for the prototype SMR projects. All these instruments are not unique for the SMRs and have been used in nuclear industry before. Experience of innovative non-nuclear technologies could be used for the development of mechanisms that would support moving the SMR technology from the prototype phase to the stage of commercial deployment (i.e., factory production). Specifically, the Working Group of the UK government in its recommendations calls for the establishment of initiate on advanced manufacturing supply chain for the SMRs similarly to what was previously done for the offshore wind [II-6].

After the prototype stage the government support of SMR technology would decrease with private and institutional investors taking over as the main sources of financing. The key distinctive characteristics of the SMR projects is their scale: NOAK SMR projects are expected to require the amount of funding an order of magnitude less than the large LWRs. These will still be very significant amounts ranging from hundreds of millions to USD 1 - 2 billion, however, the number of market investors being able to support such projects would increase very significantly, differentiating SMRs from the current large LWR projects that usually require involvement of major banks (often government-owned or controlled), Export Credit Agencies (ECAs) and the state itself through the system of guarantees or state-to-state loans. Another factor opening SMR projects for the broader pool of potential investors is the shorter construction time reducing uncertainties and thus the investors' risks [II-3]. Factory production of post-prototype SMR units should additionally decrease the level of uncertainty associated with the project.

In previous sections significant part of the discussion was devoted to potential decrease of the SMR projects' costs to make them comparable or potentially lower than those of large LWR projects (per MW(e) of installed capacity). These costs were the overnight ones and factors affecting them are modularization, mass production, integrated design etc. However, the costs of financing could represent the significant share of total project costs. Due to the higher predictability and lower amount of investment needed the interest rates for the NOAK SMR projects could be expected to be lower than for the large nuclear. For the multi-unit plants the interest rates could be further reduced for the consequent SMR units after construction of the first reactor. The impact of these factors on the costs of capital for SMRs would be determined by the expectations of investors and by construction and operation experience of the first prototype SMRs. Specifically, the offsetting factor negatively affecting the risk perception by investors could be the highly innovative nature of technology used in SMRs (e.g., of Generation-IV type).

II-8. OPENING NEW MARKETS FOR SMRS

Potential demand for the SMRs globally will ultimately determine the future of technology, including the shift to factory production, advanced modularization and unlocking the benefits of economies of scale by volume. The previous discussion implicitly assumes potential competition of SMRs with LWRs (e.g., in terms of construction costs per MW(e) of installed capacity), i.e., competition in large markets with integrated grids. Given the focus of SMRs on mass production this assumption is generally reasonable. Moreover, the prototype SMRs will likely be constructed predominantly in vendor countries with advanced and established nuclear supply chain to demonstrate the viability of technology.

However, as of May 2021 there are only 32 countries operating the nuclear power (out of 172 Member States of the IAEA)[18], with a few more nations currently constructing or planning their first large NPPs. Consequently, SMRs would be competing with large LWRs in these countries only. The specifics of SMR technology and the scale of small nuclear projects could potentially open completely new markets for the SMRs in addition to those where large nuclear is operated or being considered today.

II-8.1. Countries with smaller grids

The smallest capacity that could be installed under the large nuclear power project with contemporary design starts from 1000 MW(e) (in case of the NPP with only one reactor). This makes the use of nuclear prohibitive for countries with smaller national grids where even one large nuclear power reactor would represent the significant share of the grid. The reason is that as any power station the NPP cannot operate at 100% capacity as it needs to be stopped for maintenance and refueling. In case of larger grids this is not the problem as other power plants

[18] https://pris.iaea.org/PRIS/home.aspx

could compensate for the NPP during outages but in smaller energy systems tripping of large reactor unit would lead to a sizable disturbance.

The general suggestion is that single nuclear reactor unit should not account for more than 10% of the minimum load of the total energy system in the country [II-10]. Basically, this makes the deployment of large LWR problematic for the countries with total installed capacity under 10 GW(e) unless they are well-connected to the larger grids of neighboring countries. According to the U.S. Energy information administration (EIA), in 2018 only 64 countries globally had over 10 GW(e) of installed electricity capacity[19]. Under this approach, SMRs would get access to the new national markets that previously were not considering nuclear due to the size of national grids. Specifically, SMRs with 100 MW(e) capacity could be potentially suitable for the countries with installed capacity of only 1 GW(e), which according to the EIA statistics would add 67 more potential new national markets for the SMRs.

II-8.2. Areas with limited potential for nuclear siting

Due to the nature of nuclear technology and strict safety requirements for nuclear installations the number of sites where the NPP could be constructed is limited. Among the most important requirements are the geological stability of location and access to water for cooling. The smaller physical size of the SMR units could make additional sites available for the NPP construction. Smaller capacities of SMR units also mitigate the requirement for access to large volumes of water for cooling [II-3]. The challenges for choosing potential site for the NPP is particularly important for smaller countries with high energy demand, where there could be no appropriate sites for the large LWR construction. More siting options associated with SMRs (even based on conventional LWR and not advanced Generation-IV technology) potentially makes these nations new markets for small nuclear.

Siting issue is not limited to smaller countries and is relevant for larger nations as well. For example, according to the ETI study, the upper limit for large nuclear capacity in England and Wales based on analysis of the stock of suitable sites and using contemporary technology (by 2050) is 35 GW(e) [II-11]. This is an absolute limit with maximum number of units allocated at each possible site. In practice this is not realistic. Moreover, ETI study shows that Carbon capture and storage (CCS) plants requiring large construction areas and access to cooling water could be competing for the appropriate sites with large LWR projects decreasing the options for large nuclear deployment in the UK further. These factors could potentially provide additional opportunities for the SMRs.

II-8.3. Remote areas and islands

SMRs could be a natural solution for the niche markets isolated from national grids like remote Northern areas or the islands. Large nuclear is not suitable for these areas due to the limited energy demand. However, the specific characteristics of SMR technology, including dispatchability (reliable operation with predictable output), infrequent refueling (minimized outage time and reduced fuel transportation costs) and minimal dependency on the natural conditions (e.g., extreme temperatures) makes it a viable option for these markets [II-12]. In fact, the first SMR put in commercial operation globally (floating NPP ‘Akademik Lomonosov’) was manufactured to provide energy for the isolated area in Chukotka region in Northern Russia.

[19] https://www.eia.gov/international/data/world/electricity/electricity-capacity

SMRs that could be potentially deployed in these niche markets would be competing with diesel fuel as the only viable alternative currently being used in these areas. In this case the requirements for economic competitiveness would be different as the electricity costs in the North are high due to logistical challenges associated with transportation of diesel fuel and spare parts to distant regions and construction requirements for the power plants in extreme weather conditions. Specifically, the costs of electricity in Northern Canada are more than twice higher than the average for the country[20]. For the energy systems of isolated islands, in addition to land based SMR designs, floating NPPs could have additional advantages due to their portability. Floating NPPs could be 100% manufactured by vendor at the production site (factory and shipyard) with only connection to grid needed to be done on-site.

Niche markets offer opportunities not only for the SMRs but also for microreactors (capacity under 20 MW(e)). Specifically, potential market for small nuclear is the energy-intensive mining facilities in isolated parts of the globe. Depending on the amount of demand and the size of facility microreactors, especially portable ones, could be an appropriate option. Scientific research stations in Polar regions could be yet another market, especially for the microreactors. This approach was already used at the U.S. McMurdo Station in Antarctica powered by the nuclear reactor in 1968-1972. However, very specific requirements of niche markets could contradict the standardization approach based on mass factory production of NOAK SMRs due to the necessary adjustments in reactor designs for local conditions [II-3].

II-8.4. Countries with smaller national income

Conventional large LWR NPPs are often called infrastructure megaprojects due to their size, complexity, and costs [II-13]. Construction of a 1000 + MW(e) NPP with even a single reactor unit for USD 5 - 8 billion could be prohibitively expensive for many countries even if overall size of the grid and availability of potential sites are not the concern. For some countries committing to nuclear at such scale without previous operational experience could be a problem due to the risks associated with the project of such scale. SMRs could be an appropriate compromise for the countries interested in nuclear power and development of their national capacity that cannot afford or consider premature the construction of large LWRs.

These countries most likely would not be constructing the prototype SMRs and would be the users of already mature NOAK designs therefore not being affected by the issues of establishing factory manufacturing capacity, modularization, and cost reduction due to learning. Securing funding for the sub-USD 1 billion SMR project could be much easier for the nations with smaller national incomes and repayment of loan would be much less of a burden for the national economy in comparison with multi-billion LWR project. Additionally, given that for the factory produced SMRs much higher share of the modules would be manufactured at vendor's facility with on-site works to significant extent being reduced to installation, the risks associated with less experienced national labor force would also be reduced. This could potentially lead to the more favorable loan conditions making the SMR project more affordable in terms of costs of financing. After construction of the first small reactor and based on its operation experience the country could make a decision in favor of installing additional SMR units or consider the option of large LWR in case if enough funds become available and energy demand is increasing.

II-8.5. Markets with load-following and non-electric applications

The share of variable renewable energy sources (solar, wind) is increasing in many national energy systems due to the global efforts to achieve Paris Climate Agreement goal of limiting

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[20] https://www.cer-rec.gc.ca/nrg/ntgrtd/mrkt/snpsht/2017/02-03hghcstpwr-eng.html

global warming to well below 2 °C. The challenging factor is that the production of energy from these sources depends on external conditions and is largely unpredictable. Therefore, to keep the energy system balanced, dispatchable energy sources (i.e., the energy sources with predictable and controllable output) are needed. Large nuclear is low-carbon and dispatchable, however, its ability to promptly change output depending on the demand and energy production from solar and wind power plants (load following) is limited [II-14]. Load following for large nuclear is practiced in some countries (France, Germany), however, originally large LWRs were designed as the baseload for the energy system that should operate at maximum capacity.

SMRs could potentially get additional opportunities in the markets with higher shares of renewables. It is expected that due to their design advanced SMRs would be more suitable for load following [II-3]. According to the Ernst & Young report, the SMRs could potentially change their output in 10% steps per minute from their maximum capacity [II-7]. This, however, is yet to be tested with the first prototype SMRs. Economic effectiveness of using SMRs in load following regime is also questionable as reactor coolant and main steam supply systems will need more frequent replacement. Alternative approach would be to use the underutilized capacity of the SMRs for non-electric applications, e.g., hydrogen production. SMRs could also potentially provide an additional value proposition for the relevant markets in terms of other non-electric applications, e.g., district heating or desalination.

II-9. EXAMPLE: COMPARING ECONOMIC COMPETITIVENESS OF SMRS AND LARGE LWRS

Economic competitiveness of SMRs will be determined by complex combination of positive and negative impacts of the factors discussed in the previous sections. Competitiveness of the SMRs would be changing over time depending on previous construction and operation experience and investors' expectations. It will also vary among markets depending on local conditions. However, despite of uncertainties, illustrative examples based on the INPRO methodology could be used for the demonstration of some differences between the SMR and large LWR projects. This section provides a hypothetical example comparing economic competitiveness of the SMR and large LWR projects depending on the discount rates and electricity price levels. The second example (in the next section) analyzes potential impacts of construction delays and cost overruns on these projects. The examples in both sections compare a large power reactor project with a 4 - unit SMR power plant with the same nameplate capacity. The technical and economic data assumptions are provided in Table II-1.

TABLE II-1. TECHNICAL AND ECONOMIC DATA FOR A LARGE REACTOR AND A MULTI-UNIT SMR PLANT

	Large reactor	SMR
Capacity	1200 MW	4 x 300 MW
Construction time	6 years	3 years for one unit
Plant life	60 years	60 years
Capacity factor	90 %	90 %
Overnight construction cost	US $ 4 800/kWe	US $ 6000/kWe for 1st unit; reduced cost for subsequent units – 85 % for 2nd; 75 % for 3rd & 68 % for 4th unit
Fuel cost	US $ 10/MW·h	US $ 10/MW·h
O&M cost	US $ 10/MW·h	US $ 10/MW·h
Discount rate	5 % and 10 %	5 % and 10 %

Overnight construction costs of the first SMR unit are assumed to be 6000 USD/kW(e) but the subsequent units are expected to cost less due to sharing of some infrastructure facilities and learning. The overnight construction costs for a large reactor and the 4-unit SMR power plant are shown in Fig. II-2. The average overnight capital costs for the SMR units in this example are still higher than for the large reactor.

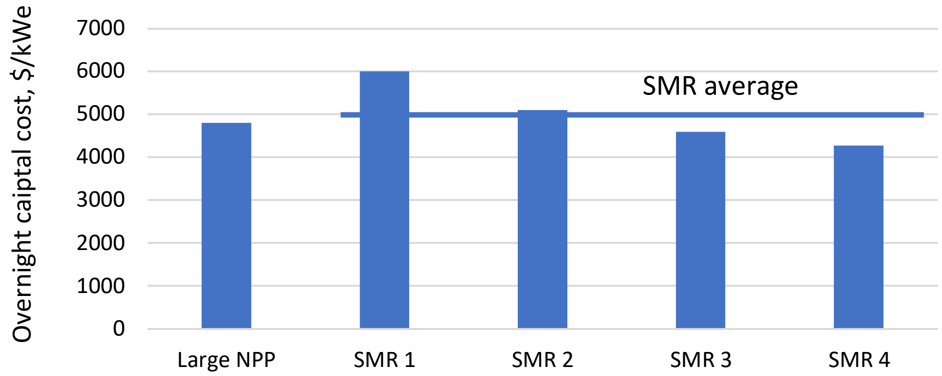

FIG. II-2. Assumed overnight cost of a large reactor and the SMR units.

The construction and operation schedules for each of the reactors are shown in Fig. II-3. In this example the construction is expected to take 6 years for a large reactor, and 3 years for the SMR units. Though the construction of the first SMR unit could take longer than of the subsequent ones, in this simplified case construction times for all small reactors are assumed to be equal. The operational life is assumed 60 years for all reactors.

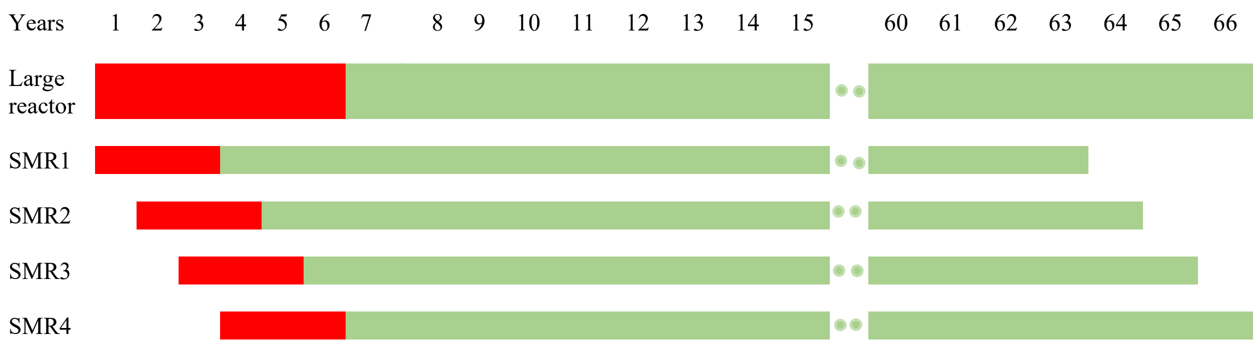

FIG. II-3. Construction and operation schedules for large reactor and SMRs.

Figure II-4 shows the total costs of construction including interest during construction (IDC) for the large reactor and the 4-unit SMR power plant. The IDC is calculated for 5% and 10% discount rates. The IDC for the 4-unit SMR power plant is smaller than for the large reactor for both discount rates due to the shorter construction time of the SMRs. Therefore, considering the IDC, the total construction costs of the 4-unit SMR power plant are lower than for the large reactor even though the overnight costs of the SMRs are higher.

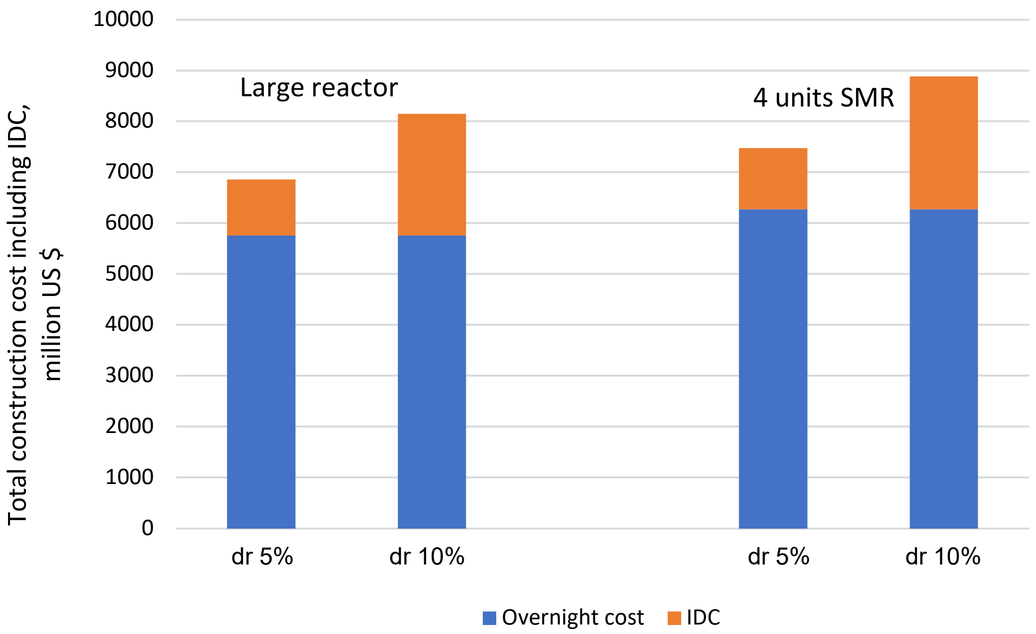

FIG. II-4. Total construction costs including interest during construction (IDC) for large reactor and 4-unit SMR power plant.

Based on the construction costs and technical and economic data in Table II-1 the levelized unit electricity costs (LUEC) for each reactor can be calculated for both discount rates (Fig. II-5). The LUEC for the first SMR are the highest and decrease for the subsequent SMR units. For the 4 SMR units combined the LUEC are lower than for the large reactor for both discount rates. The difference in LUEC between a large reactor and a 4 - unit SMR power plant is larger for the higher discount rate.

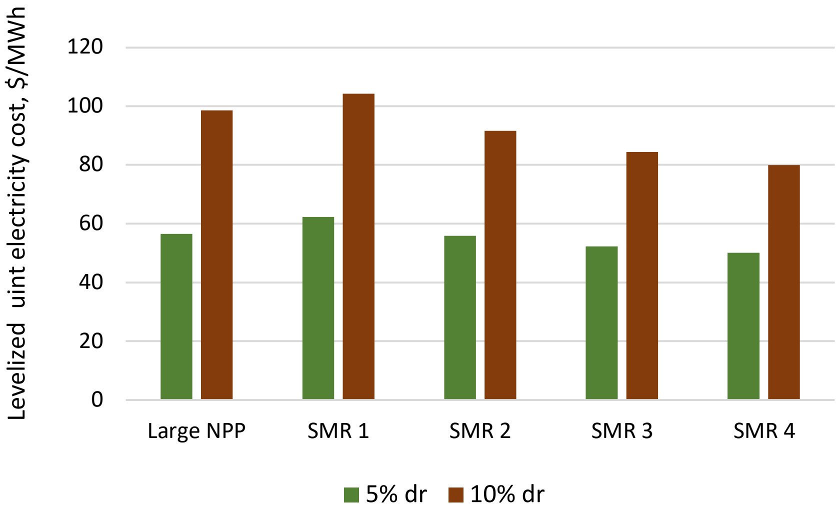

FIG. II-5. Levelized unit electricity cost (LUEC) for a large reactor and the SMRs. Legend: dr -discount rate.

The internal rate of return (IRR) is a common investment indicator based on comparison of investing in the project with alternatives having similar risk levels. Higher IRR means that the investment option is more attractive. Figure II-6 shows the IRRs for all reactors in this example for electricity prices 60 USD/MWh and 80 USD/MWh. The IRR for the first SMR unit is the lowest (4.7% for electricity price 60 USD/MWh and 7.2% for 80 USD/MWh price). The IRRs for the subsequent SMR units increase because of assumed reduction in their construction costs. For the entire 4 - unit SMR power plant the IRRs are 5.7% and 8.5% for 60 USD/MWh and 80 USD/MWh electricity prices respectively. The corresponding IRR values for the large reactor are lower making the 4 - unit SMR power plant a more attractive option in this example.

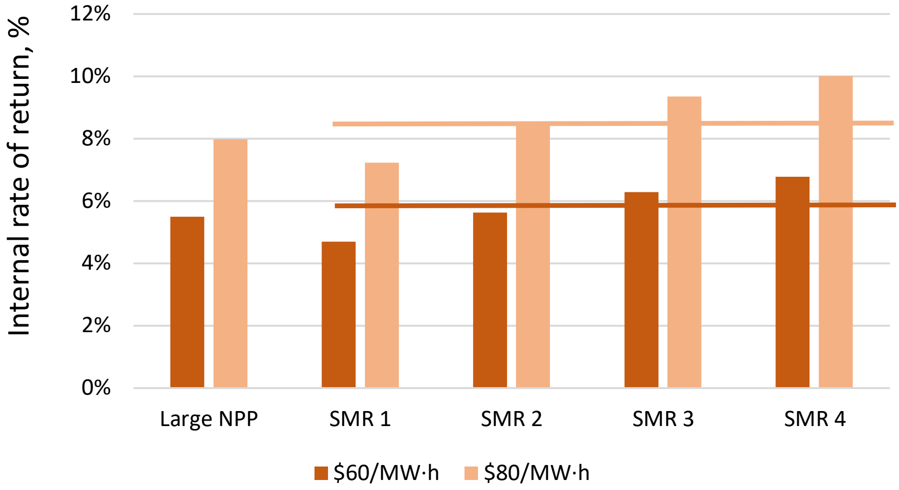

FIG. II-6. Internal rate of return (IRR) for a large reactor and the SMRs for electricity prices of US 60 and 80 per MW·h.

Figure II-7 compares the net present values (NPVs) of a large reactor and the 4-unit SMR project. At 5% discount rate the NPVs are positive for both electricity price levels. The NPV for the 4 - unit SMR project is higher than for the large LWR in this case. However, at 10% discount rate all NPVs are negative, even for higher 80 USD/MWh electricity price.

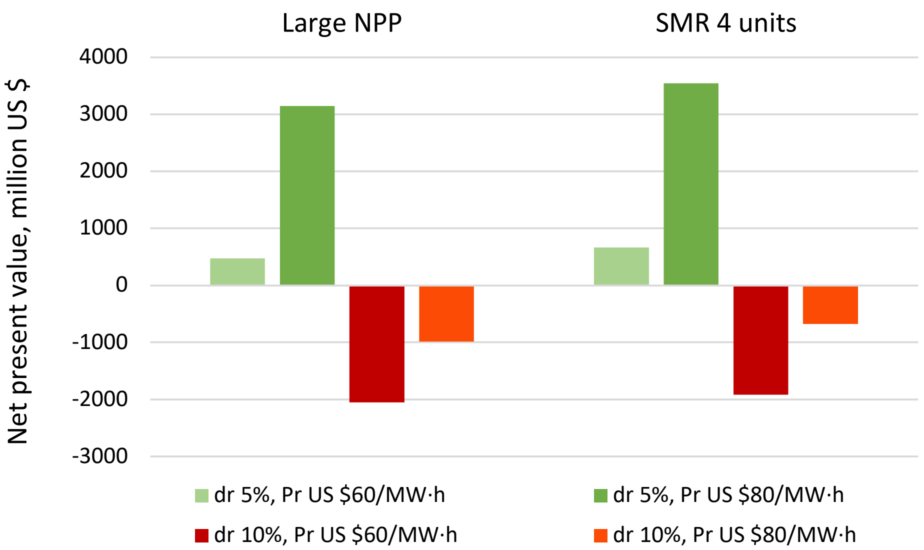

FIG. II-7. Net present value (NPV) for a large reactor and the 4-unit SMR power plant. Legend: dr – discount rate, Pr – electricity price.

Sensitivity analysis could be helpful for understanding the impacts of different factors on the electricity costs. Figure II-8 demonstrates the impact of changes in capacity factor on the LUEC (costs increase with as the capacity factor decreases) and Fig. II-9 illustrates the discount rate impact (the LUEC increase with higher discount rate).

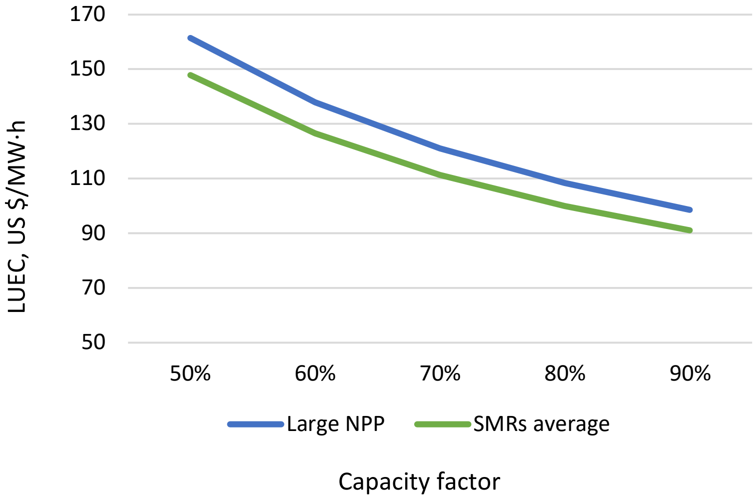

FIG. II-8. LUEC sensitivity analysis depending on capacity factor.

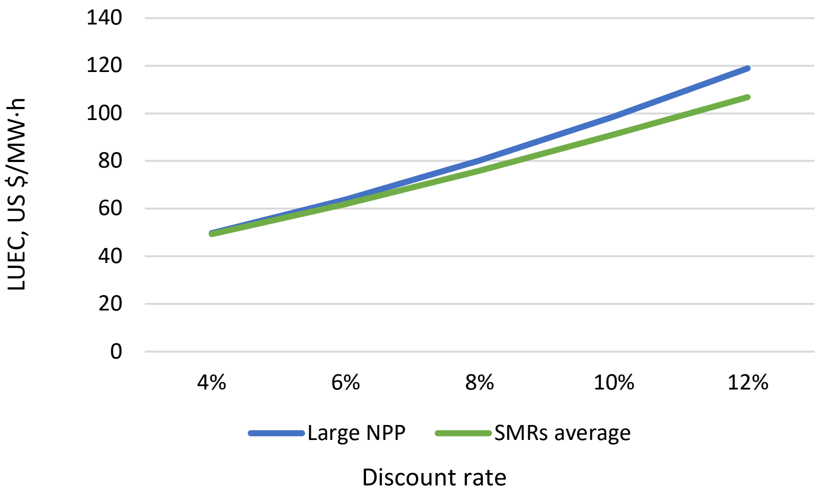

FIG. II-9. LUEC sensitivity analysis depending on discount rate.

II-10. EXAMPLE: CONSTRUCTION DELAYS AND COST OVERRUNS' IMPACTS ON SMRS AND LARGE LWRS

The example provided in this section compares potential impacts of delays and cost overruns on the multi-unit SMR project and large LWR using INPRO methodology. In this illustrative case the reactor units from the previous example face a two-year delay in construction and a 10% increase in their overnight construction costs. The revised construction and operation schedules are shown in Fig. II-10.

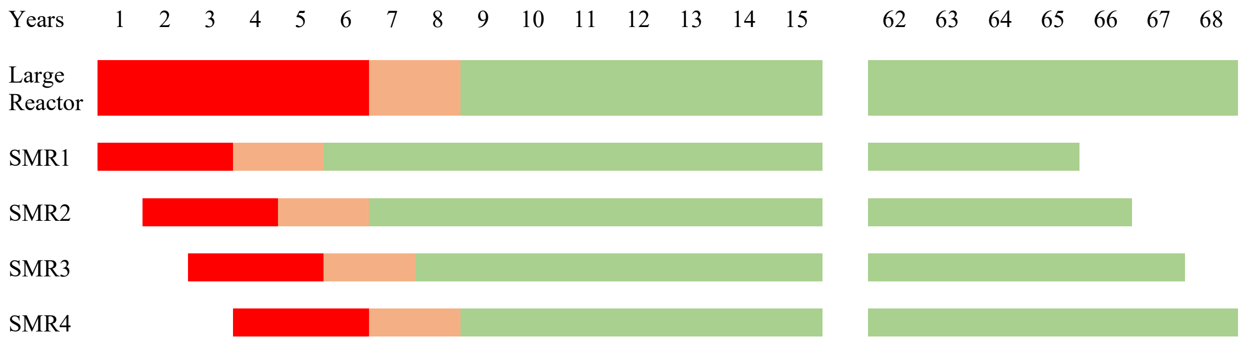

FIG. II-10. Construction and operation schedules with two-year construction delay for the large reactor and the SMRs.

With the revised construction schedule the IDCs for 5% and 10% discount rates from previous example change accordingly (Fig. II-11). Specifically, for 10% discount rate the total costs of construction including IDC would increase to USD 10 billion for the large LWR and to USD 9.6 billion for the 4 - unit SMR power plant. The IDC would increase from 41% of the overnight costs (in base case scenario without delay) to 57% for the delayed construction case (Fig. II-12).

These cost increases for the large LWR and the SMRs would considerably affect their economic competitiveness. The LUEC for the base case and the delayed construction case are shown in Fig. II-13. The LUEC for the large LWR increases by 18% for the delayed case (from 98 USD/MWh to 116 USD/MWh). For the 4 - unit SMR power plant the impact of two-year delay on LUEC is significantly smaller with only 4% increase (from 95 USD/MWh to 98 USD/MWh). These numbers demonstrate lower sensitivity to construction delays of the SMR projects under this example conditions.

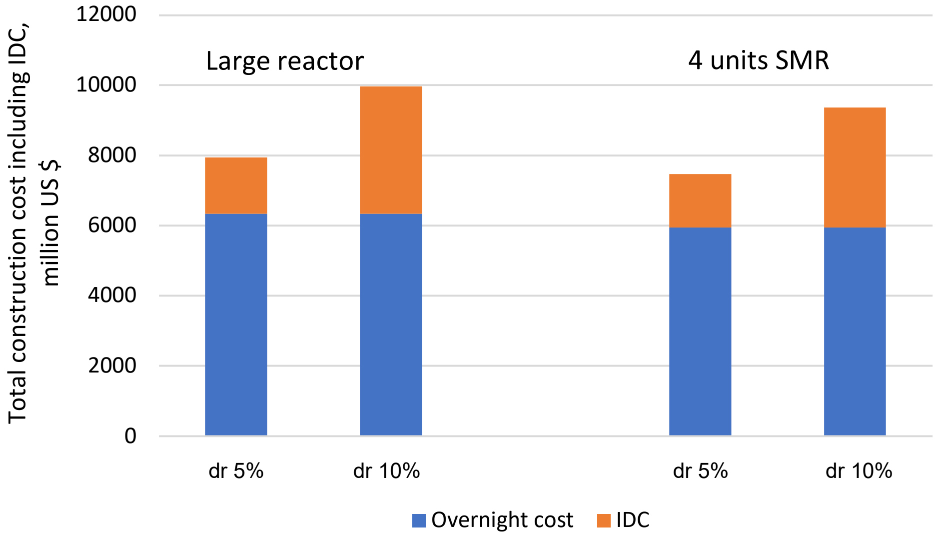

FIG. II-11. Total costs of construction including IDC for the delayed construction case (delay of 2 years and 10% increase in the overnight cost). Legend: dr 5% - discount rate of 5%, dr 10% - discount rate of 10%.

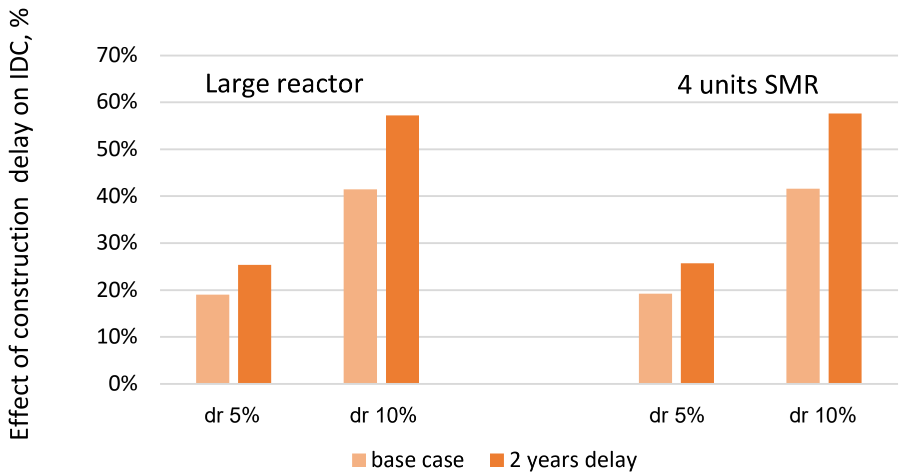

FIG. II-12. IDCs for the base case and delayed construction case. Legend: dr 5% - discount rate of 5%, dr 10% - discount rate of 10%.

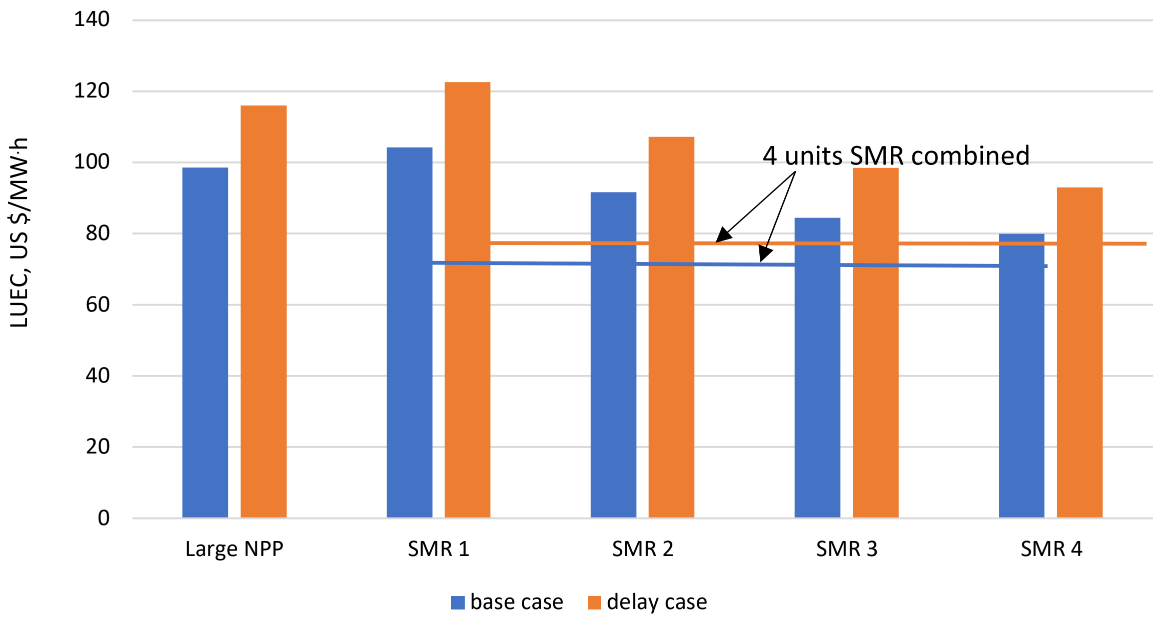

FIG. II-13. LUEC for the base case and delayed construction case (the discount rate is 10%).

The IRRs for the delayed case are shown in Fig. I-14. Comparison of the IRRs for the base case and the delayed construction case (Fig. I-15) shows that construction delays and cost overruns would impact the SMR project similarly to the large LWR. With 80 USD/MWh electricity price the IRR would decrease from 8.5% (base case) to 7.3% (delayed case) for the 4 - unit SMR project, and from 8.0% (base case) to 6.9% (delayed case) for the large reactor.

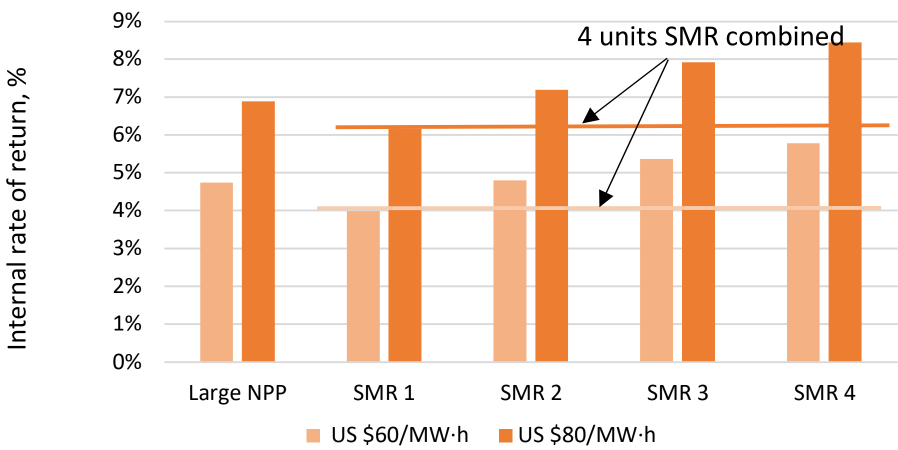

FIG. II-14. Internal rates of return (IRRs) for the delayed construction case (delay of 2 years and 10% increase in overnight cost).

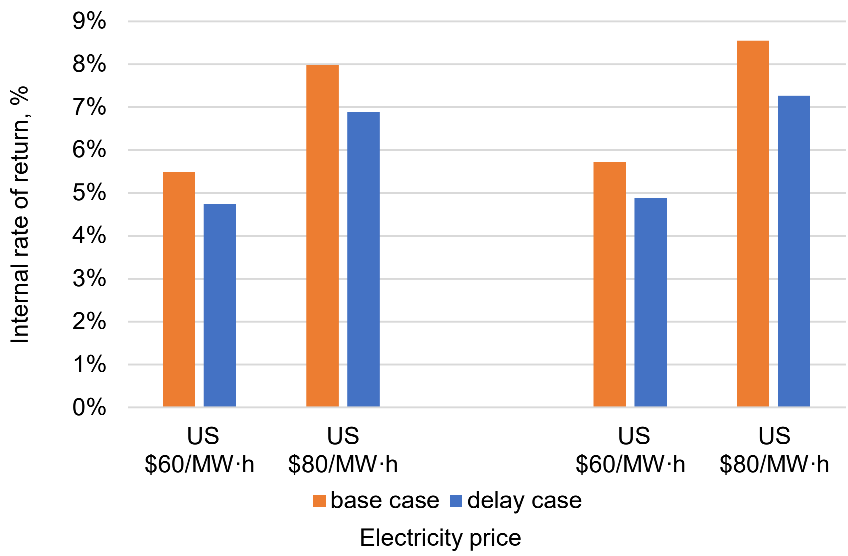

FIG. I-15. IRRs for the base case and delayed construction case.

The net present values (NPVs) of the large reactor and the 4 - unit SMR projects are compared in Fig.II-16 for 5% and 10% discount rates with 60 USD/MWh and 80 USD/MWh electricity prices. In all cases the NPVs are negative except for the case with 5% discount rate and 80 USD/MWh electricity price.

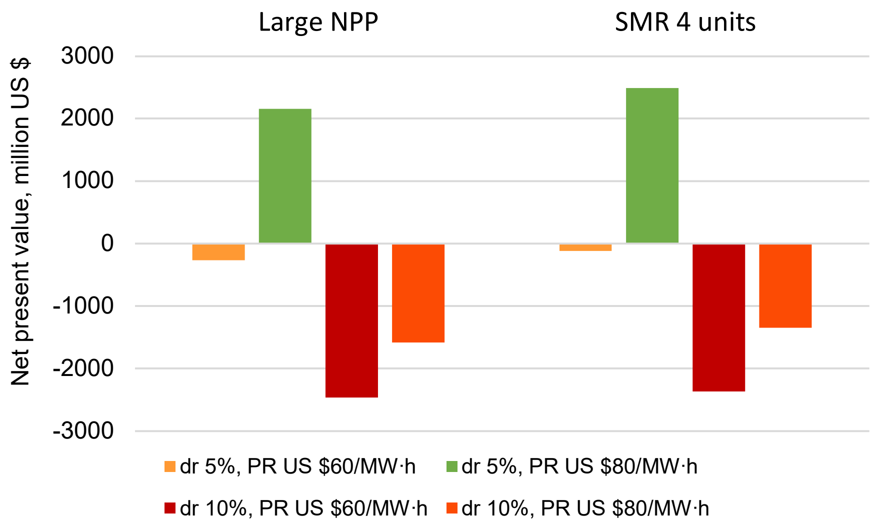

FIG. II-16. NPVs of the large LWR and 4-unit SMR projects for delayed construction case (delay of 2 years and 10% increase in overnight cost). Legend: dr – discount rate in %, PR - electricity price in US $/MW·h).

REFERENCES TO ANNEX II

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ANNEX III

NEST – NESA ECONOMICS SUPPORT TOOL

Annex III, available only in electronic form, provides a description of the main inputs and outputs of the nuclear energy system assessment (NESA) economics support tool, abbreviated as NEST. Having been amended by the “Analysis” block, NEST is currently being used not only to support NESAs but to perform comparative economic evaluations of nuclear energy system or technology alternatives, as well as non-nuclear energy alternatives, such as organic fuel fired and hydro power plants and renewables. Annex III also includes some illustrations of NEST application, in particular, as comes to calculation of levelized unit cost of a nuclear fuel cycle (LUFC).

The supplementary files for this publication can be found on the publication’s individual web page at www.iaea.org/publications.

LIST OF ABBREVIATIONS

ASENES	Analysis support for enhanced nuclear energy sustainability.
GDP	Gross domestic product
GHG	Greenhouse gas
IAEA	International Atomic Energy Agency
IDC	Interest during construction
IMF	International Monetary Fund
INPRO	International Project on Innovative Nuclear Reactors and Fuel Cycles
IRR	Internal rate of return
LUAC	Levelized unit life cycle amortization cost
LUEC	Levelized unit electricity cost
LUFC	Levelized unit fuel cost
LUOM	Levelized unit O&M cost
LWR	Light water reactor
MESSAGE	Model for energy supply strategies alternatives and general environmental impacts
NEA	Nuclear Energy Agency
NES	Nuclear energy system
NEST	NESA economics support tool
NPP	Nuclear power plant
NPV	Net present value
O&M	Operation and maintenance
ROI	Return on investment
PWR	Pressurized water reactor
SIMPACTS	Simplified approach for estimation of impacts of electricity generation
SWU	Separative work unit
WASP	Wien automatic system planning model

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