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Economic Performance Indicators for Nuclear Power Plants

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ECONOMIC PERFORMANCE INDICATORS FOR NUCLEAR POWER PLANTS

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FOREWORD

From a global perspective, it is clear that there is no single group of key economic and financial measures that are applicable and useful for all countries and regions. The extent to which deregulation and privatization is occurring varies considerably throughout the world, with some countries continuing to foster regulated monopolies or government subsidies for power generation, while in others retail and wholesale electricity is sold in truly open market, competitive situations. Consequently, the requirement for key measures of financial and economic success for the nuclear power industry will continue to be diverse from one region or country to another.

This report has been prepared for the benefit of nuclear plant managers and operators. Its primary purpose is to identify and define a number of economic performance measures for use at nuclear power plants operating in deregulated, competitive electricity markets.

In addressing the value of economic measures, the report presents and discusses a general definition and classifications of nuclear economic indicators within the context of regulation, competition and the economic requirements for constructing, operating and decommissioning nuclear plants. Categories of economic measures, traditionally used in competitive enterprises, that have potential application in the operation of nuclear plants are also presented. A number of industry observations are discussed and presented as critical factors leading to a series of improvement strategies for the continued development and implementation of economic indicators, beyond those provided in this report, as well as for other related IAEA activities on the implementation and further development of the Nuclear Economic Performance Information System.

On the basis of the collective opinions and judgements of the representatives of the participating countries, the report provides a 'preliminary' set of nuclear economic performance indicators, presented in standard Excel format, which includes detailed definitions, sample calculations, formulas and automated data input tables to facilitate the calculation and use of each indicator.

This publication reflects the discussions and research performed by the scientific investigators who participated in the coordinated research project on national approaches to correlate performance targets and O&M budgets.

The IAEA expresses its appreciation to all who participated in the meetings and discussions during the preparation of this report. The IAEA is particularly grateful to the former chairperson of the Nuclear Committee of the Electric Utility Cost Group, J. DeMella, for having chaired all the meetings held on this subject and for his collaboration and assistance in preparing the

final report. The IAEA officer responsible for this report was R. Spiegelberg-Planer of the Division of Nuclear Power.

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1. INTRODUCTION

The prospect of having performance measures that are useful in gauging the economic and financial success of business enterprises is certainly not new. It is well recognized that there are a plethora of commonly used standard measures that have been successfully employed by the business and financial community, as well as by electric utilities, throughout the world for a very long time. Measures of profitability such as return on investment, earnings and revenue generation are among the many commonly and successfully used. What is new and is, in fact, becoming a clear imperative for the nuclear power industry is the recognition and acceptance that, with the advent of deregulation, utility privatization and competitive generation markets, key measures of success used at nuclear generating plants must now include the traditional metrics of a successful business enterprise as well as those of plant performance, safety and reliability.

Clearly, when it comes to the safety and reliability of nuclear plants, there is no question as to the industry's achievements in developing and implementing superlative nuclear performance indicators and the processes to engage them, on a worldwide basis. Over the years, the world nuclear industry's development and application of WANO and PRIS performance indicators have contributed significantly to substantial improvements in the operating and safety performance of nuclear power plants. Although many nuclear plants have traditionally embraced simple economic measures of resource utilization and budget performance, little has been achieved to date to standardize and implement economic and financial performance measures that help to assure economic competitiveness and financial success at the nuclear plant generating level.

This report is complemented by the inclusion of Annexes I–VII, which provide examples of performance indicator data.

1.1. IMPORTANCE OF AN INTEGRATED APPROACH TO NUCLEAR POWER PLANT OPERATIONS

Traditionally, at the company or corporate level, regulated electric utilities were chiefly concerned with business matters of electricity supply, demand and price, including strategic and financial planning, capacity planning, and electricity price and rate regulation. Strategies, goals and decision making concerning these business matters were more often formulated and measured on a consolidated basis, often combining the impacts, risks and rewards of individual electricity generating facilities within a given utility enterprise.

Electricity generating facilities such as nuclear power plants focused primary management attention on strategic and tactical matters having to do with plant operating performance, safety and reliability. Typically, under utility rate regulation, it would be unusual for the managements of nuclear plants to concern themselves with the market price of the electricity they produced and the potential revenues and earnings directly associated with a specific nuclear generating plant. With the advent of electricity deregulation, the open market sale of electricity and the 'unbundling' of generating companies from former utility monopolies, electricity generating plants are increasingly facing strong price competition and significant downward pressure on operating and production costs. The imperative to be competitive and profitable at the individual nuclear plant level is becoming increasingly evident. Under past financial regulation and oversight, nuclear plants were often subject to 'cost of service' regulatory approaches that required only minimal attention to operating costs and, to a lesser extent, investment returns on plant equipment. Generally, from the perspective of nuclear power plant managements, either profit or return on investment was not of particular concern or it was simply expected and to some degree assured through the various regulatory processes governing electricity rate design. Clearly, the key financial measures and metrics of supply, demand and profitability were viewed at the regulatory and utility corporate levels but infrequently integrated within the management decision making processes at the operating nuclear plant level. Plant safety and reliability were most often the sole determinants of management decision making and consequently the focus of key performance measures of success.

With deregulation and the open market pricing of electricity, the business and financial success of operating nuclear plants must be considered to a much greater extent, along with the successful achievement of safety and reliability objectives. In developing strategic and operational goals, nuclear plant managers will be required to embrace and articulate clear and measurable business objectives and goals which not only assure the achievement of safety and reliability but in addition eliminate unnecessary costs and identify investment opportunities. These goals must, in addition, balance operating and safety risk while optimizing plant revenues and earnings and ultimately ensure the profitability of electricity generating facilities. In doing so, it will be essential for nuclear plant managers to articulate integrated goal achievement through the application of effective, measurable economic performance indicators which are understood by all and institutionalized within the plant organization and the nuclear power industry as a whole.

1.2. VALUE OF COST DATA IN THE CONTEXT OF BENCHMARKING

With deregulation and competition, there will inevitably be a more serious and greater emphasis on the need for continuous process improvement and benchmarking activities within the nuclear electricity generation industry. The metrics required for baseline process standards and those for continuing improvement will need to embrace, integrate and correlate key plant operational, safety, and business and financial parameters. Just as the standardization and industry acceptance of safety and operational performance measures and the cooperative sharing of relevant performance best practices have, in the past, contributed significantly to industry advances in these areas, similarly, the standardization of economic measures and financial definitions and a keen sense of business literacy specifically applicable to the operation of nuclear power facilities will be required for the nuclear power industry to become and remain economically competitive.

To a large extent, much of the information along the lines of O&M, capital cost and staffing data for operating nuclear power plants is currently available to Member States and companies participating in the IAEA's Nuclear Economic Performance Information System (NEPIS) and the US based EUCG Nuclear Committee economic databases. Since 1997, in anticipation of privatization and deregulation in the world electric power industry, the IAEA and the EUCG Nuclear Committee have worked cooperatively to develop and implement NEPIS for various regions of the world. NEPIS is a nuclear plant economic performance database which principally includes detailed annual O&M and capital cost data reported by participating nuclear power plants in various world regions. Essential elements for the implementation and maintenance of standard nuclear economic performance indicators will be the framework, standardization and knowledge of the nuclear plant cost data and the standard definitions that have been incorporated into the NEPIS and EUCG Nuclear Committee economic databases.

1.3. VALUE OF DEFINING INDICATORS AT THE PLANT LEVEL

As discussed earlier, measuring economic performance for regulated electric utility companies has been a tradition at the corporate or utility company level. Financial performance indicators other than the straightforward measures of resource consumption or budget performance such as investment returns, revenues and earnings were also focused at the corporate level, often consolidating the individual performance contributions of electricity generating facilities, including nuclear power plants. Economic performance indicators specifically for individual nuclear generating plants were either not formally identified or generally not embraced and used by plant management and utility regulators. With the onset of competitive electricity generation, the requirement for financial and economic measures of performance, specifically applied and focused at the generating plant level, will be inevitable. With electricity competition, individual nuclear plants will sell their output, competing on electricity price, ultimately to ensure the safe, reliable and economic dispatch of their generation either into open spot markets or by competitive bidding for forward priced bilateral contracts. In either case, a sound and confident understanding of the operational and economic factors and key measures which gauge the competitiveness of an individual generating plant will be required. Economic and financial performance indicators will be needed for individual plants to measure, evaluate and improve continuously the operating and management processes needed to become and remain competitive in open electricity markets.

1.4. NO INDICATOR CAN BE ANALYSED INDIVIDUALLY

Generally, nuclear plant performance indicators, whether operational or economic, are not mutually exclusive. Nuclear plant managements must simultaneously take into account a number of performance measures to ensure their safe, reliable and economic operation. In viewing nuclear power plant performance, not only is there a strong dependence between individual performance variables but, in addition, good performance along one particular measure is often correlated with good performance in most other key measures of success.

Clearly, the relationships or correlations between certain traditional measures of nuclear plant performance, whether operational or economic, are quite obvious. For example, traditional nuclear plant performance indicators such as operating capacity factor, load factor, refuelling outage duration and net generation are closely related and similar in that they are all key measures of electric plant production and reliability. However, each is different in that each affords plant management a unique opportunity or challenge to establish and gauge performance goals that can significantly impact the competitiveness of a nuclear power plant. All of these measures are directly associated with, or significant drivers of, key economic measures such as operating cost, operating revenues, earnings and various measures of nuclear plant profitability, including return on investment and return on equity. In this regard, an evaluation or understanding of nuclear plant economics cannot be completely determined without also evaluating and measuring plant operating and safety performance. The converse is generally true, in particular for nuclear plants operating and selling power in deregulated electricity markets. A nuclear plant that is unsafe or unreliable, as measured by acceptable industry standards of operation, will likely be uneconomic when operating in regulated or unregulated markets.

Not as obvious or intuitive but further illustrating the strong relationships between key nuclear performance measures is the economic measure of electricity price. Electricity price in competitive markets is the measure over which plant management has least control yet it is the variable that has the greatest impact on most other economic outcomes and to a large extent on other key operating performance measures. In competitive markets, the seasonal variations in electricity price will become a significant determinant in establishing goals and measuring performance along operational measures such as refuelling outage date and duration, and consequently the optimization of net generation and plant operating revenues.

Decisions having to do with operating performance obviously cannot be made without careful consideration of their relationship to cost and economic performance, in particular, in deregulated markets. It follows then that no one performance indicator can be analysed individually without careful consideration of its relationship and impact on other key nuclear plant measures.

2. IMPLICATIONS OF UTILITY DEREGULATION AND ELECTRICITY MARKET COMPETITION

The implications of electricity deregulation are, and will continue to be, pervasive and significant. Not only will the fundamental monopoly regulatory concepts of managing electricity utilities change but deregulation will also have a profound and dramatic impact on the way electricity generating plants are managed and operated.

In the past, under the various approaches to financial regulation, the economic benefits normally attributed to competition or what would have otherwise been derived from competitive or open market forces, were assumed to be embodied in, and inherent to, the various processes, methods and principles of financial oversight of utility companies by regional, state and municipal regulatory authorities.

Typically, under the various forms of regulated monopolies, a utility company, in exchange for an exclusive franchise to produce and sell electricity in a particular region, was obligated to provide an adequate supply to all consumers wanting it, at a price that was 'just and reasonable'. The determination of adequate supply and reasonable rates was a matter of interpretation by utility companies as well as their regulators. In essence, the ultimate economic benefits, normally attributed to price equilibrium, in balance with supply, demand and other market forces, were expected to be achieved and sustained through a complex political process of financial regulatory oversight, in which utility companies were usually reimbursed for most if not all of their annual expenses or their cost of service and additionally allowed to earn a 'reasonable' rate of return on plant investments. For example, regulated US electric utilities, based on the reasonable revenue requirements and cost of service principles, were allowed by their utility commissions to earn a reasonable return on their investments. Although it is difficult to define what is reasonable compared with other expense components of utility cost, US regulatory commissions and the courts have attempted, over time, to establish a 'zone of reasonableness' which is founded upon the standards of capital attraction and comparable earnings. In general, the zone of reasonableness is such that the rate of return approved by a utility commission should allow a utility to attract capital investments and should also be reasonable, compared with other non-regulated companies that have similar investments subject to similar risks.

The result was often escalating electricity prices and excess generating capacity caused by justifying unnecessarily high reserve margins based on long planning horizons (typically 20 years or greater) with extrapolated demand requirements that were generally in excess of what actually occurred over time. In any event, to the extent that a utility company justified to its regulators the need for additional capacity and the added expenses to operate it, the utility was usually reimbursed for its cost and profited accordingly.

Although the regulatory process varied from country to country and from region to region, the fundamental principles that influenced and ultimately determined the price or tariffs to consumers were generally the same. Utilities' revenue requirements were founded upon complex cost of service which emphasized and allowed the recovery of all reasonable costs, including operating expenses, tax and depreciation of investments and in addition assured a reasonable rate or return on all outstanding investments.

The consequence was that through regulation of electricity rate design, the ultimate price of electricity was determined by the aggregate of costs to produce it, independent of the forces of supply and demand.

In the nuclear power industry, over time, this process, in conjunction with obvious requirements and imperatives for improvements in safety and reliability, not only had a profound impact on the costs of constructing new nuclear generating facilities, but also on the costs of operating, maintaining and decommissioning them. Over time, the costs of constructing new nuclear power plants rose dramatically from \$200–300/kW(e) to more than \$6000/kW(e) in certain regions of the world.

With the transition to deregulation, the price of electricity will ultimately be determined by economic factors within the market place. In the following paragraphs, a number of implications for operating nuclear plants in competitive electric markets are addressed and discussed.

2.1. NUCLEAR ASSET REVALUATION

Deregulation of electric utility monopolies in the United States of America is becoming extensive, with many states having recently enacted deregulation laws. These laws typically require that electric utility monopolies unbundle their services and divest themselves of their generation assets through direct sale or competitive auction. The result has been that the asset value of these facilities is revalued by the competitive desire and forces of the market place to own and operate them in a truly competitive wholesale electricity market. In certain cases, in exchange for their prior, exclusive franchise to generate and sell electricity in a specified region, the former owners are allowed to receive a reasonable return on those assets that become 'stranded' in the process of divestiture. Stranded is typically defined as the difference between the net asset value of the power plant prior to divestiture and the price at which the facility is sold. Most nuclear units recently sold in the USA have been sold at prices substantially less than their asset values prior to divestiture.

2.2. SHIFT OF FINANCING RISK

Under deregulation, the risks, costs and rewards associated with debt versus equity financing of nuclear plants will inevitably change. In order to attract sufficient capital at reasonable cost, the capital structure of an enterprise is intentionally chosen such that a portion of the total invested capital is financed through debt or the issuing of bonds and the remainder is financed through the issuing of additional common and preferred stock or equity. For the case of regulated nuclear utilities, the ratio of debt to equity, of total invested capital often exceeds 50:50 or even 70:30. In this situation, with long term assured returns, the risk associated with debt investment is relatively low and so is the rate of return or interest rate. Typically, in the USA, the weighted average cost of capital for regulated utilities is in the order of 10–15%, including interest on long term debt in the order of 6–10% (assured long term returns, low risk to investors, relatively low rate of return). Under deregulation, the financial risks associated with nuclear power plants operating in competitive markets are not clearly understood. For example, the greater risks of operating in competitive markets may be increasingly assumed by owners as opposed to debt holders and the capital structure, cost and rewards of generating companies will change accordingly.

For regulated utilities, the annual depreciation expense (return of investment) is the net depreciation, calculated on an annual basis, for the recovery of all invested capital over the life of the generating unit, frequently computed on a straight line basis. Since recovery of depreciation expense is generally assured by the regulator, the book life or the time period needed to recover the investment is usually the licence life or operating life of a nuclear unit. The operating life of a nuclear power plant is typically 40 years in the USA, 12 years in India, and in Brazil it started with 20 years but this has now been extended to 30 years. Compared with an unregulated or competitive enterprise, 40 years' of assured return of investment is a relatively long period of time over which to recover investments with little or no risk incurred.

For generating companies operating in competitive markets, return of and return on investment are not as assured. Only to the extent that a nuclear plant can generate sufficient revenues, through the competitive sale of electricity and other generation products at market prices, can there be sufficient income to cover all costs, including depreciation and interest on debt, as well as sufficient earnings to provide a reasonable rate of return or dividends to the common shareholders. Also, the risks associated with competitively operating nuclear power plants in unregulated markets are not well understood. Consequently, the risks are relatively high, as are the assumed rates of return. In recent economic evaluations of the operation of nuclear power plants, it is not uncommon to assume the weighted average cost of capital to be in excess of 15–20% with a typical book life in the order of 10–20 years.

2.3. MORE SOPHISTICATED ANALYSIS TOOLS

The cost of capital and the expected returns on investment may be significantly different for different companies and generating facilities competing in the same market. In general, since the remaining life and the net asset value of any nuclear power plant may be different, the return may very well be different, assuming all other costs and key variables to be the same. In determining economic value, each situation must be carefully evaluated, based on its individual merits, taking into account assumptions made for all significant economic and operational variables. These variables include:

(a) The investment required to construct a new nuclear unit;
(b) The current asset value;
(c) The design power rating (MW(e));
(d) The levels of nuclear operating performance assumed (operating capacity factor, refuelling outage duration, etc.);
(e) The mode of financing capital investment (debt versus equity);
(f) The projections of annual O&M, administrative and general (A&G) and fuel expenditures;
(g) The book life assumed for depreciation of nuclear assets;
(h) Consideration of life extension;
(i) The assumed rates of cost escalation;
(j) The levels of risk tolerance assumed for selling the output of the unit (high risk/reward — energy sold on spot market, low risk/reward — energy sold by power purchase agreements or bilateral contracts).

Compared with the past, more sophisticated tools will be required to conduct effective analyses such as dynamic computer modelling of significant nuclear operational, financial and economic variables.

Consider a recent example in the US (New England) market place. Over the past few years, deregulation laws in most New England states required that electric utilities divest their generation assets through auction or negotiated sale. At that time, about four years ago, Entergy, through negotiated sale, purchased the Pilgrim nuclear power station from the Boston Edison Company for a price of approximately \$20/kW(e). This price was significantly less than the original capital cost as well as the asset value of Pilgrim station at the time of the sale. Since Entergy's price was clearly market driven, it is reasonable to assume that in determining the value it was willing to pay Entergy had to make certain assumptions about the future price of energy, as well as all other significant financial and operational variables for operating Pilgrim station. At the time of this sale, typical spot market projections for the wholesale price of energy and capacity in New England were in the order of \$25/MW·h and \$15/kW(e) respectively. This equates to an 'all in' price of approximately \$31/MW·h. Also at the time of the sale, other large New England electric utilities that had substantial equity positions and/or operating experience in other nuclear generating facilities showed little or no interest in purchasing Pilgrim, even at the 'bargain' price of \$20/kW(e). Approximately two years later, in the same but more mature wholesale electricity market, Dominion

Resources purchased, at auction, Millstone Station for approximately \$550/kW(e); the highest resale price paid for a US nuclear generating facility up to that time. Apparently, Dominion's justification for this seemingly high capital investment was based on its energy price projections of approximately \$40/MW·h with expected returns in the 15–20% range and nuclear performance at relatively high industry levels, typical of its past nuclear operating experience at Surry and North Anna. By US industry standards, both Entergy and Dominion (Virginia Power) are considered to be excellent nuclear operators. The average wholesale price of energy for the ISO New England regional transmission organization is currently in the order of \$65–70/MW·h. All other financial and operational variables considered, if the current energy prices in New England are sustained, both Entergy and Dominion Resources stand to earn substantial profits on the purchase of these nuclear facilities.

2.4. PLANT LIFE EXTENSION

Under deregulation, the economic reasons needed to justify a decision to grant nuclear plant life extension will require complex evaluation of not only production cost but, additionally, other key economic and financial variables including return on investment, return on equity, busbar cost, revenues, net earnings, etc. The economics should be evaluated on a unit by unit basis, not only with respect to current and projected nuclear performance, but also by careful comparison with other non-nuclear generation alternatives.

For example, in accordance with US law, nuclear power plants are licensed by the Nuclear Regulatory Commission (NRC) to operate for a period of 40 years with an option available to renew their operating licence. The licence renewal rule establishes detailed requirements and a process to renew nuclear plant operating licences for up to 20 additional years. The focus of this process is to require the utilities to manage the potentially adverse effects of ageing on the key operational and safety systems and components of nuclear units. In addition, utilities are required to evaluate the potential environmental impact of having extended the licence life of a unit. A US licensee may apply to renew its operating licence from 20 to 5 years prior to the current licence expiration. By the end of 2000, the NRC approved 20 year extensions to the operating licences of Baltimore Gas & Electric's Calvert Cliff (2 units) and Duke Power's Oconee (3 units). Approximately 30 of the 103 US operating units had either applied for or had informed the NRC of their intention to apply for licence renewal by 2003. By 2015, the initial operating licences of 45 of the 103 US units will have expired. The cost associated with applying for and obtaining NRC approval for life extension is estimated to be in the range of \$10–40 million.

These costs do not include the additional refurbishment costs that may be required as a result of the life extension approval process. Estimates for nuclear plant refurbishment have been put in the $200–400 million range, per unit, and typically require substantial capital investment.

2.5. NUCLEAR PLANT PROFITABILITY

Traditionally, in typical regulated electric utilities, profit and loss or income statements as well as other financial measures were prepared and evaluated at the operating company level or the holding company level and did not include detailed information at the nuclear plant level. With the advent of deregulation and competition, utilities and generating companies are now looking more carefully at the revenues and earnings of individual and combinations of nuclear generating units.

Nowadays, the practice of preparing detailed financial statements, including income statements, at the generation unit level, is becoming more common. A typical pro forma income statement, prepared at the nuclear unit level, used for financial planning purposes is included in Annex V. An explanation for the various components of the income statement presented in Annex V is given below.

The operating revenue of a nuclear power plant consists of:

(a) Energy revenue — revenue earned by the sale of net electrical energy at the unit energy price ($/MW·h);
(b) Capacity revenue — revenue earned by the sale of plant capacity at the rate ($/kW(e)) settled.

From the operating revenue, operating expenses are deducted to arrive at the operating profit. The operating expenses consist of:

(a) O&M costs, which are the total direct costs incurred in operating and maintaining the nuclear power plant;
(b) A&G expenses, which are the total indirect costs, including the allocated costs from the headquarters towards O&M of the plant;
(c) Fuel costs, which are the total costs associated with fuel utilized for the operation of the plant for the period of one year.

The difference between the operating revenue and operating expenses is the operating profit before payment of interest, tax, depreciation and amortization (if any) which is also designated as profit before interest, tax, depreciation and amortization (PBITDA).

Interest paid on the debt capital is an element of expenditure in the income statement. The debt capital is used either in the investment of the plant or in the working capital of the operation. Another element of expenditure in the income statement is depreciation. Depreciation is provided for the wear and tear of the assets used and consequent reduction in their life. Depreciation will not result in cash outflow for the company and therefore it is a notional expenditure only reflected in the book of accounts.

Tax may be payable to the federal government, the state government and the municipal authorities. Generally, tax is payable on the profit made by the company. However, municipal tax may be payable for the properties carried by the company in the municipal area.

Amortization is the distribution of large abnormal expenditures over a number of years rather than the absorbing of the entire expenditure in the year in which it was incurred. The share of amortized expenditure in one year is reflected in the book of accounts as expenditures in that year. Earnings usually refer to net earnings of the company after deduction of interest, tax, depreciation and amortization (if any) from the operating profit.

2.6. SIMPLIFICATION OF COMPLEX REGULATORY ACCOUNTING

Under deregulation, independent power producers (IPPs) and utility generating companies which do not have utility monopoly status would not be subject to the highly complex accounting requirements and methods that have evolved under utility regulation, such as accelerated depreciation, tax normalization and the methods required by utilities to account for investments, leases, expenses and consumption of nuclear fuel. Deregulation will likely simplify these processes.

2.7. ALLOCATION OF CORPORATE EXPENSES

The process of deregulation can have serious implications on traditional allocation methods used for apportioning corporate administrative expenses (indirect O&M costs) to various operating functions including nuclear generation. The allocation of administrative costs to regulated and unregulated functions must be accomplished in a reasonable way so as to meet the reasonable test of regulation as well as the competitive test of the market place. Theoretically, neither test will tolerate unreasonable or unnecessary costs.

A hypothetical example is a case where an electric utility is required, by deregulation law, to divest itself of a large nuclear asset, currently valued in billions of dollars. As a result of divestiture, it is not unreasonable to assume that the new asset value of that facility, based on market forces, may become substantially less (tens to hundreds of millions of dollars). Obviously, if the allocation of administrative expenses were originally based on asset value, either a new method must be devised or a substantial reduction in headquarters' expenditures would have to occur, or both. In the USA, in fact, deregulation and utility combinations and mergers have resulted in extensive downward pressure on utility corporate headquarters' administrative costs.

2.8. ADVANCEMENT OF BUSINESS LITERACY

With the transition to competitive generation, nuclear plant management and analysts at all levels will need to embrace and implement financial and business concepts into the day-to-day operations of nuclear plants. A much greater sensitivity to, and awareness of, fundamental business and economic principles will be required. The development of sound business literacy will become an imperative for all nuclear plant decision makers.

2.9. STANDARD BENCHMARKING PROCESS

Successful competition of an enterprise most often occurs at the margin of continuous improvement and the promulgation of new, more efficient ideas, innovations and technologies, not by harbouring old concepts and dwelling on dated, past successful practices. In open markets, successful companies compete best, not for what they accomplished in the past but rather for what innovations they will make in the future. In order for the nuclear power industry to compete successfully among the power generation alternatives, the need for continuous improvement through the sharing and emulation of industry best practices will become an imperative. A standard benchmarking process for comparing and emulating the performance of the best nuclear generating companies would inevitably complement the development and application of the economic performance indicators included in this report. Since the current emphasis of this report is concerned with the development of standard economic indicators for application within individual countries, some additional analysis and methodologies (e.g. standards for currency conversion) will be required for the broader application of the indicators among participating countries in support of a benchmarking process.

3. RATIONALE FOR ECONOMIC PERFORMANCE INDICATORS

With the advance of deregulation and the introduction of competitive electricity markets, the integration of financial, as well as safety and operational, strategies for individual nuclear plants will become paramount.

Traditionally, other than the minimization of expenses and, to some extent, the making of incremental capital investments, nuclear plant managers and operators were chiefly concerned with the safe, reliable operation of their plants. As such, their primary focuses were on goal achievement and performance measures whose value contribution related to these areas of a nuclear operation. In conjunction with other non-nuclear forms of generation, the overall performance of the business aspects of a nuclear enterprise were, more often than not, left to the purview of the utility corporate management and financial regulators. For example, under regulation, it would be unusual for nuclear plant managers to be concerned about fluctuations in energy price, optimization of plant revenues, unit earnings, return on investment and the like. The optimization of revenues or earnings of a single nuclear unit or plant were not usually addressed. More appropriately, the revenues of a generating company or utility company would be tracked against some financial business standard or goal. With the advance of deregulation and the need to integrate safety, reliability and economic decision making, a much greater emphasis must be placed on economic measures and their value contribution to the operation and financial success of individual nuclear units.

The following section will attempt to develop a general definition for nuclear economic indicators and also to classify them in accordance with standard categories of economic value contribution.

3.1. NUCLEAR ECONOMIC INDICATORS — A DEFINITION

For the purpose of this report, the terms economic performance indicator or measure and financial performance indicator or measure are synonymous and are used interchangeably. The addition of the prefix nuclear to economic measure is not, in any way, intended to imply that nuclear financial performance indicators are notably unique or useful only to the business of operating nuclear power plants. On the contrary, most financial indicators and economic concepts used to gauge the economic value and financial health of any enterprise are also applicable to the nuclear power generation business. To a large extent, the economic success of operating nuclear power plants in competitive markets is dependent upon the recognition, acceptance and application of fundamental economic principles and measures traditionally applied to any successful business enterprise.

Theoretically, the performance associated with any aspect of constructing or operating a nuclear power plant affords some degree of economic consequence. Therefore, one could conclude that any measure of nuclear performance, in one way or another, can be construed as being economic. There is little argument that good and bad performance, of any kind, typically correlates with good and bad economics. So how has the nuclear economic performance indicator been defined?

Within the context of this report, the term economic performance indicator is intended to mean a measure that, either directly or indirectly, significantly influences or contributes to the economics of any factor value and the financial health of a nuclear enterprise.

This definition may at first appear somewhat broad and encompassing. However, a more general definition, as indicated above, will allow a reasonable degree of latitude in appropriately classifying as economic, nuclear performance measures traditionally considered operational, if the particular behaviour or outcome being measured has significant implications for the economic value of a nuclear power plant. Availability factor and outage duration are good examples of this. Clearly, these measures have their roots in traditional nuclear plant operational goals and strategies. In the past, prior to the reality of competitive generation, it would have been unusual to associate strategic decisions regarding the duration of nuclear refuelling outage with a nuclear plant financial goal of optimizing electricity revenues. Revenue generation was traditionally only a concern of electric utility corporate financial planning departments, senior executives and financial regulators and as such was typically identified as a goal at the company or utility level but not articulated for a specific electricity generating unit or plant.

Although one aim of this report is to identify economic performance measures within the context of electricity deregulation, confining the selection of economic measures for this purpose only would be limiting, especially considering the diversity of the regulation and privatization activities throughout the world. Many nuclear utilities continue to operate entirely within regulated regions and for the near term it is reasonable to conclude that many will continue to do so. For example, in the USA, regardless of the downward pressure on electricity rates and the apparent preoccupation with the notion of utility deregulation, the majority of states still remain regulated. By way of observation, it is interesting to note that some of the best performing (economically or otherwise) nuclear utilities in the USA are located in the southeastern region where deregulation appears to have a weaker foothold. Nevertheless, nuclear utilities within this region have recently seriously embraced and undertaken the identification of effective financial and economic performance measures in support of the operations of their nuclear plants.

Further, the process of deregulation is inherently transitional, evolutionary and extensive, so much so that in some situations it has been referred to as re-regulation. Any study which seeks to identify and implement a standard set of economic performance indicators should consider economic measures which may have strong implications on the financial outcome of construction and operations of regulated as well as non-regulated nuclear power facilities.

From an economic perspective, the operation of a nuclear power enterprise embodies a series of major processes that extend through several distinct, but strongly interrelated phases. This economic life cycle begins with extensive planning, engineering and construction, extends throughout the operational phase (including life extension) and concludes with decommissioning. In certain cases, depending upon the option chosen, decommissioning may be extensive. Owing to the capital intensive nature of the nuclear power business, as well as to the relatively high operating expenditures, the economic consequence of any one phase may have serious, far reaching implications for the economic success or failure of the others. For example, the decision making process of selecting a decommissioning option, typically made during the operating phase of a nuclear power plant, may have serious implications with regard to the total cost of electricity production.

In addressing the subject of economic value and in defining and choosing the appropriate measures by which to gauge it, all phases of the nuclear enterprise should eventually be considered.

3.2. PLANT LEVEL VERSUS MARKET ORIENTED INDICATORS

Economic performance indicators can be further categorized into two major areas — plant and market indicators. Plant indicators are those that are typically under the direct control of nuclear plant management and although their value contribution is considered to be primarily economic, they tend to relate, either directly or indirectly, to activities or decisions concerning the construction and O&M of a nuclear facility.

On the other hand, market oriented indicators are those that may have significant impact or influence on the financial success of a nuclear unit but which are typically outside the control of plant managers and operators. They are usually measures or indicators relating to conditions that reflect the behaviour of the market place, which may present significant opportunities or risks to nuclear plant management and have significant influence on the economic and financial success of operating a nuclear facility.

The distinction between plant level and market level economic measures is an important one, if for no other reason than to emphasize, to nuclear plant managements, the profound relationship existing between market conditions and the economic success of nuclear plants, a relationship that was rarely of concern in the past. Under electric power regulation, operators of nuclear power plants paid primary attention to plant issues relating to the safety and O&M of a nuclear unit. The conditions of the market in which electricity was sold were not usually of particular concern at the plant operating level. Nuclear units were typically base loaded and, regardless of market conditions, it was generally assumed that all the energy produced would be dispatched and sold irrespective of price, supply or demand. If a nuclear plant were not in service, replacement energy would inevitably be provided by one means or another.

Conversely, in a deregulated, competitive electricity market, as in any open market enterprise, price is one if not the most significant driver of economic outcome.

3.3. POTENTIAL NUCLEAR ECONOMIC INDICATORS

The following tables (Tables 1–8) include a number of economic performance indicators which may have potential application for nuclear power plants operating in both regulated and unregulated regions. About 50 indicators were identified and discussed in the IAEA project. These were classified according to their application.

Although some of the indicators have traditionally been used as operational measures (outage duration, energy availability factor, etc.), they are being presented here as economic measures since they directly impact achievement of economic value. Although it is well understood that safety indicators and other nuclear performance indicators typically under the purview of WANO, PRIS, etc., can impact the economic performance of nuclear plant, they are not considered to be within the scope and purpose of this report.

TABLE 1. MEASURES OF PRODUCTIVITY

Performance indicator	Unit of measure
Unit capability factor	%
Energy availability factor	%
Capacity factor/load factor	%
Unit loss capability factor	%
Forced loss rate	%
Net generation	kW·h, MW·h
Gross revenues	$, $ \times 10^3$, $ \times 10^6$
Revenue growth	%
Refuelling outage/planned maintenance duration	d
Maintenance backlog	Number of activities
Net generation by staff	kW·h/number of staff
Thermal performance	%

TABLE 2. MEASURES OF PROFITABILITY

Performance indicator	Unit of measure
Capital turnover ratio	%
Dividend payout	%
Debt ratio	%
Debt to equity ratio	%
Net earnings	$, $ \times 10^3$, $ \times 10^6$
Earnings before interest, tax, depreciation and amortization (EBITDA)	$, $ \times 10^3$, $ \times 10^6$
Earnings per common share	$, $ \times 10^3$, $ \times 10^6$
Earnings growth	%
Operating ratio	%
Profit margin	%
Return on equity	%
Return on investment	%

TABLE 3. MEASURES OF SAFETY

Performance indicator	Unit of measure
Collective radiation exposure	mSv
Unplanned automatic scrams per 7000 h critical	Number
Industrial safety accident risk	Number/time
Safety system performance	%
Fuel reliability	%
Chemistry performance indicator	%

TABLE 4. MEASURES OF VALUATION

Performance indicator	Unit of measure
Net present value	\$, $\$ \times 10^3$, $\$ \times 10^6$
Internal rate of return	%

TABLE 5. MEASURES OF OPERATING EXPENSE

Performance indicator	Unit of measure
Busbar cost	c/kW·h, mills/kW·h, \$/MW·h
Going forward cost	c/kW·h, mills/kW·h, \$/MW·h
Fuel cost	kW·h, MW·h
Heavy water cost	\$/MW·h
O&M costs (direct and indirect)	\$, $\$ \times 10^3$, \$/MW(e), \$/MW·h
Indirect cost	\$/MW·h
Production cost	c/kW·h, mills/kW·h, \$/MW·h

TABLE 6. MEASURES OF CAPITALIZATION

Performance indicator	Unit of measure
Annual capital expenditure	\$, $\$ \times 10^3$, $\$ \times 10^6$
Debt ratio	%
Debt to equity ratio	%
Inventory level	\$, $\$ \times 10^3$, $\$ \times 10^6$
Inventory turn rate	%
Net asset value	$\$ \times 10^6$

TABLE 7. MEASURES OF MARKET CONDITION AND ORIENTATION

Performance indicator	Unit of measure
Weighted average price of energy (electricity) sold	c/kW·h, \$/MW·h
Energy (electricity) price	c/kW·h, \$/MW·h
Forward energy (electricity) price	c/kW·h, \$/MW·h
Demand (load)	MW·h
Demand growth (load growth)	%
Supply (capacity/availability)	MW(e)
Capacity growth	%
Inflation rate	%

TABLE 8. MEASURES OF THE COST OF SERVICE (REVENUE REQUIREMENTS)

Performance indicator	Unit of measure
Cost of debt	\$
Cost of equity	%, \$
Weighted average cost of capital	%, \$
Depreciation expense	\$, $\$ \times 10^3$, $\$ \times 10^6$
Fuel expense	\$, $\$ \times 10^3$, $\$ \times 10^6$
O&M costs (direct and indirect)	\$, $\$ \times 10^3$, $\$ \times 10^6$
Training hours per employee	h/employee
Minimum revenue requirements	\$, $\$ \times 10^3$, $\$ \times 10^6$

4. ECONOMIC PERFORMANCE INDICATORS

4.1. GENERAL

Various possible economic indicators are listed and examined in this report. These indicators were scrutinized by the group of experts from the point of view of relevance, significance, applicability in the countries participating in the study and also for broad applicability of the indicators internationally. The group has prioritized the indicators according to the aforementioned criteria. Out of the prioritized list, the top 15 indicators were chosen, monitored for a certain period of time and validated by the group to be used for nuclear power plant performance monitoring.

Nevertheless, key measures of financial and economic success for the nuclear power industry will continue to vary widely from one region or country to another. The list of financial indicators provided in this section (and in Annex III (Figs III-1–III-15)) of the report was developed specifically to accommodate this diverse requirement. In fact, the economic indicators selected are a reflection of the diversity of the requirements of the countries that participated in the coordinated research project to develop them.

Overall, the indicators are intended to have application in different regions throughout the world. In using the indicators, individual countries and Member States should select from the list those economic measures that are best suited to their specific circumstances and financial requirements. In situations in which nuclear plants continue to operate in regulated monopoly markets, the more traditional measures that simply track the expenditure or accumulation of O&M and capital costs should continue to be the appropriate choice. In regions where wholesale and retail electricity are transacted in spot markets or through power purchase agreements and competitively bid bilateral contracts, performance measures which seek to optimize the generation of revenues, plant reliability and availability, minimize operating costs and focus on the profitability at the nuclear generating plant level, will have greater application.

For each of the selected economic performance indicators, the following section discusses the purpose and potential application, provides a detailed definition of the overall indicator, including definitions and sources of the key data elements, and includes a sample calculation. A standard Excel spreadsheet template has been developed for each of the indicators recommended by the group (see Annex III). The standard spreadsheets are intended for actual use by Member States and nuclear plant operators that choose to track and view the performance of a particular indicator. The spreadsheets are prepared for yearly and monthly monitoring of each indicator using US dollars. The choice of the yearly and monthly monitoring of each indicator depends on the intention of individual regions or countries to control their specific applications and financial requirements. For national use, the spreadsheets should be adapted to the country's currency by changing the data table formulas (Annex IV (Tables IV-1–IV-2)) and the indicator spreadsheets (Annex III).

Each of the indicator spreadsheets also includes detail definitions, a formula for calculating the indicator and a graphical plot of the indicator based on representative, hypothetical data for a one year period. To facilitate the application and use of the standard spreadsheets, data update tables (see Annex IV) have been developed for each indicator which allow users to input data elements and key information at a level of detail commensurate with performance data typically available and collected by nuclear plant management and operators. The Excel workbook that includes the standard spreadsheets and data tables for each performance indicator is an integrated package or model in that each data table is automatically linked to its appropriate spreadsheet such that when data are input into the table all appropriate calculations are performed and the indicator spreadsheet is automatically updated.

The purpose of data input tables is to facilitate the application and use of standard spreadsheets developed for each indicator, which allow users to input data elements and key information. The data will be collected through a computerized (Excel workbook) survey that will be designed to allow users easily to enter, change, update and submit information on a monthly or yearly basis on a nuclear generating unit or plant. Each data is automatically linked to its appropriate spreadsheets, so any data input into the table are automatically updated in the indicator spreadsheet.

4.2. DESCRIPTION OF SELECTED PERFORMANCE INDICATORS

4.2.1. **Production cost** (c/kW·h)

Purpose:

Although frequently used when making economic comparisons and analysing industry trends, production cost does not represent the total cost of producing electricity on a c/kW·h basis. It does, however, provide an effective measure of the variable and controllable costs of the O&M of nuclear units. Typically, the units for production cost are calculated in c/kW·h or mills/kW·h. The costs used in the calculation of production cost do not include annual carrying costs associated with capital investments. Similar measures to production cost, which do include capital related costs, are busbar cost and going forward cost (GFC). These measures do include capital carrying costs and, to a greater extent, represent the total cost of producing electricity at a nuclear unit.

Definitions:

Production cost (c/kW·h) is defined as the sum of nuclear O&M cost plus nuclear fuel cost, for a given period, divided by the net generation produced over the same period.

Total O&M cost ($) is the total, non-fuel direct O&M cost consistent with NEPIS Account 2000 and expressed in dollars.

Fuel cost ($) is the total cost associated with a load of fuel in the reactor which is burnt in a given period. It is the cost consistent with NEPIS Account A1900 and expressed in dollars.

Net generation (MW·h) is the electrical energy produced during the time period as measured at the unit outlet terminals, i.e. after deduction of the electrical energy taken by the unit auxiliaries and the losses in transformers that are considered integral parts of the unit. It is the net generation consistent with NEPIS Account A1650.

Calculation:

$$\text{production cost (c/kW·h)} = \frac{\text{nuclear O\&M (\$) + fuel cost (\$)}}{\text{net generation (MW·h)}}$$

4.2.2. **Staffing level** (staff/MW(e))

Purpose:

The staffing level, sometimes referred to as ‘body count’ or ‘FTEs’, is an effective measure relating to the labour component of nuclear O&M cost. It is often used as a relative performance measure in the benchmarking of nuclear power plants. Staffing level per MW(e) normalizes this measure for plant size (megawatt capacity) for use in direct comparison with other nuclear plants. Frequently, it has been shown that relatively low staffing levels (utility employees and long term contractors) correlate positively with good performance, along with other operational and financial measures. Since the labour component of direct O&M cost and other indirect costs such as medical benefits, pensions, etc., are directly proportional to staffing level generally, lower staffing levels lead to an overall reduction in the cost of producing electricity.

Definitions:

Staffing level (staff/MW(e)) is defined as the ratio of the number of permanent nuclear staff, at a given point in time, divided by the design electrical capacity of the plant or unit.

Permanent nuclear staff (FTEs) includes on-site (located at the nuclear facility) and off-site (located at headquarters, etc.) utility employees and long term contracted labour for the nuclear facility. Permanent nuclear staff excludes short term contractors and services.

Long term contractors (FTEs) are non-utility (contracted) employees in staff augmentation positions of duration greater than six months.

Design electrical capacity net (MW(e)) is the net generating capacity of the unit or plant consistent with NEPIS Account A1645.

Calculation:

$$\text{staffing level (staff/MW(e))} = \frac{\text{permanent nuclear staff (FTEs)}}{\text{design electrical capacity net (MW(e))}}$$

4.2.3. **Nuclear O&M cost** ($/kW(e))

Purpose:

Nuclear O&M cost represents the single largest component of major operating expense associated with the total cost of operating and maintaining a nuclear power generating facility. As such, the tracking of nuclear O&M cost, as a primary financial performance indicator, is essential whether operating in regulated or competitive market conditions. In a regulated environment, nuclear O&M cost directly impacts the revenue requirements of an electric utility and consequently determines the electricity rates or tariffs paid by all classes of consumers. For nuclear plants operating in competitive markets, on a dollar for dollar basis, the expenditure of nuclear O&M directly impacts the earnings or profit of the nuclear plant and the operating company. Nuclear O&M, expressed in $/kW(e), normalizes this measure according to unit or plant size, allowing for direct comparison and benchmarking with other nuclear units and plants.

Definitions:

Nuclear O&M cost ($/kW(e)) is defined as the total O&M cost for a given period divided by the net design electrical capacity of the unit or plant.

Total O&M cost ($) is the total, direct, non-fuel, annual reccurring labour and material costs including operations, maintenance, engineering support services and plant administration. It is the cost consistent with NEPIS Account 2000 and expressed in dollars.

Design electrical capacity net (MW(e)) is the net generating capacity of the unit or plant consistent with NEPIS Account A1645.

Calculation:

$$\text{O\&M (\$/kW(e))} = \frac{\text{total O\&M cost (\$)}}{\text{design electrical capacity net (MW(e))}}$$

4.2.4. **Refuelling outage or overhaul planned maintenance duration** (d)

Purpose:

Refuelling outage duration and major maintenance outage duration (expressed in days) are effective performance measures which relate directly to the productivity and reliability of nuclear power plants. As such, tracking the performance of outage duration not only has a direct impact on traditional operational measures such as annual capacity factor, but also, significantly, relates to the financial opportunity to optimize electricity generation revenues and achieve and sustain required levels of earnings for the company. The tracking of major outage duration is not only important from the perspective of minimizing the absolute outage duration, but is equally important with regard to the optimum timing or seasonal scheduling of an outage. In competitive electricity markets, as energy price and therefore revenue opportunities change dramatically during different calendar periods and in different regions of the world, the tracking and timing of refuelling and major planned maintenance outage duration become essential to achieving profitability of a nuclear plant.

Definitions:

Refuelling/maintenance outage duration (d) is defined as the number of days, breaker to breaker, since the reactor was shut down to perform the most recently completed refuelling outage or major maintenance outage. Refuelling/

maintenance outage duration is consistent with NEPIS Accounts A1715 and A1690 for the most recently completed refuelling outage or maintenance outage.

Major maintenance outage (d) is usually a non-refuelling outage of more than 20 d duration.

Calculation: N/A

4.2.5. **GFC** (c/kW·h)

Purpose:

Similar to production cost, the GFC is a financial performance measure that characterizes a portion of the busbar or total cost of producing electricity. From an arbitrary point in time, GFC includes all categories of cost for a given period associated with the production of electricity, including expenses, tax, inventory, depreciation and return on investment, except that all outstanding investment carrying costs are intentionally excluded from the calculation. Since, at any given point in time, a substantial portion of nuclear plant investments are sunk, having been made and decided upon substantially in the past, a large portion of the costs included in a busbar or total cost calculation is not within the control or decision authority of the current nuclear management.

By choosing an arbitrary, reasonably current point in time as the starting basis for determining GFC, the impact of large sunk investments, such as the original cost of the plant, is eliminated from the GFC calculation. Consequently, as an economic performance measure, although somewhat arbitrary in magnitude, GFC is more suited to measuring the benefits and consequences of current management decision making as they relate to expenditures and investments in the operation of a nuclear unit. In this regard, GFC can be an effective economic measure for establishing meaningful performance goals that closely relate to the competitive price of electricity and for which nuclear management and employees can be held reasonably accountable. In light of recent sales of existing nuclear power plants in the USA and elsewhere, where the net asset value of a nuclear plant has been revalued at the sale or auction price of the unit, busbar cost and GFC, in theory, become one and the same. All investment carrying costs included in the total cost calculation are determined from the time of the sale of the facility and are based on the new or revalued investment or sale price of the unit or plant.

Definitions:

GFC (c/kW·h) is defined as the sum of nuclear O&M cost plus indirect cost plus fuel cost plus the carrying cost on going forward net outstanding capital (GFNOC) additions and inventory for a given period divided by the net generation over the same period.

GFNOC is defined as the total investment in capital additions less the total depreciation of capital additions from a specified point in time through the period of the calculation.

Cost of GFNOC is defined as the weighted average cost of the GFNOC.

Total direct O&M cost ($) is the total, non-fuel direct O&M cost consistent with NEPIS Account 2000 and expressed in dollars.

Total indirect cost ($) refers to corporate, non-fuel O&M expenses, including labour and materials, relating to a specific nuclear generating facility (plant or unit), not directly associated with the on-site O&M of the plant or unit including liability, property and replacement power insurance, costs of pensions, medical benefits and payroll taxes, and corporate administrative and general expenses which would be allocated to nuclear such as legal, human resources, executive functions, accounting, etc. It is the cost consistent with NEPIS Account 2500 and expressed in dollars.

Total fuel cost ($) is the total cost associated with a load of fuel in the reactor which is burnt in a given period. It is the cost consistent with NEPIS Account A1900 and expressed in dollars.

Value of inventory is defined as the average outstanding inventory value ($\$ \times 10^6$) for the period of the calculation. The average outstanding inventory value is the sum of the inventory value at the beginning of the period plus the inventory value at the end of the period divided by two.

Inventory carrying cost is defined as the value of inventory, mentioned above, multiplied by the weighted average cost of capital used for acquiring the inventory.

Annual depreciation expense is the annual allowance for the depreciation of property representing that portion that has been 'used up' during the previous twelve months.

Net generation (MW·h) is the electrical energy produced during the time period as measured at the unit outlet terminals, i.e. after deduction of the electrical energy taken by the unit auxiliaries and the losses in transformers that are considered integral parts of the unit. It is the net generation consistent with NEPIS Account A1650.

Calculation:

GFC (c/kW·h) =

$$\frac{\text{O\&M + fuel + indirect cost + inventory carrying costs + cost of GFNOC}}{\text{net generation (MW·h)}}$$

All costs mentioned above should be expressed in dollars.

4.2.6. **Fuel cost/MW·h** ($/MW·h)

Purpose:

As a major component of nuclear production cost and busbar cost, the fuel cost, sometimes referred to as fuel expense (the dollar value of nuclear fuel consumed over a given period) is an important financial/economic measure. Fuel cost amounts to a significant portion of the total production cost of a nuclear plant or unit (in the order of 20%). Annual fuel cost, excluding the additional costs associated with heavy water replenishment of PHWRs, in the range of $3–5/MW·h is common for many operating nuclear units.

Although the cost of fuel has traditionally been an economic advantage for nuclear plants compared with fossil generation options, the continued optimization of all costs associated with efficient management of the nuclear fuel cycle will offer significant economic opportunities and challenges for nuclear plant management. Under deregulation, traditional fuel management practices such as reducing power or 'coasting' to planned refuelling dates in order to achieve optimum fuel consumption will give way to revenue optimization strategies, even at the cost of disposing of unburnt nuclear fuel.

The definition of fuel cost will likely change under deregulation. The current definition, and the complex regulatory accounting associated with it, is closely aligned to certain fundamental regulatory principles, in particular, the principle of 'used and useful'. Under this principle, for the ultimate benefit of consumers, only to the extent that real fuel expenditures and investments are used and useful for consumers or provide direct benefit for consumers in a given time-frame can those costs be reflected in the definition or measures of fuel cost and allowed to be recovered in electricity rates. In competitive electricity markets, all costs incurred by a nuclear plant in support of the nuclear fuel cycle, whether useful to consumers or otherwise, will be measured as fuel cost and incurred as an expense against earnings.

Definitions:

Fuel cost is defined as the total annual expense associated with the burnup of nuclear fuel resulting from the operation of the unit. This cost is based upon the amortized costs associated with the purchase of uranium, conversion, enrichment and fabrication services along with storage and shipment costs and inventory (including interest) charges less any expected salvage value. Payments for fuel decommissioning and decontamination and current and previous spent nuclear fuel disposal costs, including principal and interest, are also included. Where applicable, costs associated with heavy water replenishment are also included. It is the cost consistent with NEPIS Account A1900 and expressed in dollars.

Net generation (MW·h) is the electrical energy produced during the time period as measured at the unit outlet terminals, i.e. after deduction of the electrical energy taken by the unit auxiliaries and the losses in transformers that are considered integral parts of the unit. It is the net generation consistent with NEPIS Account A1650.

Calculation:

$$\text{fuel cost (\$/MW·h)} = \frac{\text{fuel cost (\$)}}{\text{net generation (MW·h)}}$$

4.2.7. Training hours per employee (h/FTE)

Purpose:

The training per employee is the key to evaluating the performance of training in the utility. It is the number of person-hours expended in training staff.

Definitions:

Training hours per employee (h/FTE) is defined as the total number of training hours expended over a given period divided by the average number of FTEs over the same period.

Training hours (h) is the total number of person-hours expended by training department staff, including overtime, over a given period. It is the number of training department person-hours consistent with the labour cost (contractor and utility employee) included in NEPIS Account 1220.

FTE is the total number of full time nuclear staff, on-site and off-site, utility employees and long term (greater than six months) contractor employees.

Calculation:

$$\text{training hours per employee (h/FTE)} = \frac{\text{training hours (h)}}{\text{FTEs}}$$

4.2.8. **Heavy water cost** (\$/MW·h)

Purpose:

In the case of PHWRs, the cost of heavy water replenished each year is significant and is included in the fuel cost. Since the cost of heavy water replenishment is a major component of the fuel cost, it is important to optimize the heavy water losses from the plant. Heavy water cost per MW·h is an effective performance indicator aimed at optimizing heavy water loss and improving economic performance of the plant.

Definitions:

Heavy water cost (\$/MW·h) is defined as the annual heavy water cost over a given period divided by the net generation produced over the same period.

Annual heavy water cost (\$) is the direct amortized annual cost of heavy water replenishment, including purchase, shipping and storage charges (only for PHWRs). It is consistent with the heavy water replenishment costs included in NEPIS Account A1901 and expressed in dollars.

Net generation (MW·h) is the electrical energy produced during the time period as measured at the unit outlet terminals, i.e. after deduction of the electrical energy taken by the unit auxiliaries and the losses in transformers that are considered integral parts of the unit. It is the net generation consistent with NEPIS Account A1650.

Calculation:

$$\text{heavy water cost (\$/MW·h)} = \frac{\text{annual heavy water cost (\$)}}{\text{net generation (MW·h)}}$$

4.2.9. **Annual capital investment** ($/kW(e))

Purpose:

Annual capital or annual investment is a key economic measure, the performance of which directly impacts the safety, reliability and profitability of a nuclear power enterprise. In both regulated and unregulated (competitive) environments, the appropriate levels of annual capital investment needed to achieve the required levels of safe and reliable operation and, at the same time, provide a competitive return to attract and sustain investors, will remain a challenge for the nuclear power industry. In the past and to some extent even today, under typical financial regulatory principles, a nuclear power plant requiring mandated safety or operational upgrades might invest hundreds of millions of dollars annually and be shut down without recording any appreciable generation and, at the same time, continue to recover sunk investment. As the electrical power industry moves towards greater deregulation and privatization, with competitive wholesale and retail electricity markets, the need to scrutinize and track new capital investments will become paramount. Clearly, only investments with a high likelihood of delivering sufficient returns will prevail. Annual capital, expressed in $/kW(e), normalizes this performance measure for unit or plant size, allowing for direct comparison and benchmarking with other nuclear units and plants.

It is recognized that different practices are employed in different countries. Some may include interest in the annual capital; others may exclude it. Therefore, the use of this set of indicators may be adapted to individual company needs and requirements.

Definitions:

Annual capital ($/kW(e)) is defined as the current annual capital investment for a given period divided by the net design electrical capacity of the unit or plant.

Current annual capital investment ($) is the total of all costs associated with improvements and modifications made during the reporting year. It is the additional capital investment made during the current reporting period, excluding interest. These costs should include design, installation, removal and salvage that occur during the reporting period. Other miscellaneous investment/capital additions such as facilities, computer equipment, movable equipment and vehicles should also be included. These costs should be fully burdened with indirect costs and exclude interest during construction. It is the cost consistent with NEPIS Account A1810 and expressed in dollars.

Design electrical capacity net (MW(e)) is the net generating capacity of the unit or plant consistent with NEPIS Account A1645.

Calculation:

$$\text{annual capital (\$/kW(e))} = \frac{\text{current annual capital investment (\$)}}{\text{net design electrical capacity (MW(e))}}$$

4.2.10. Inventory level ($\$ \times 10^3$)

Purpose:

Investment carrying costs associated with maintaining nuclear plant inventories can amount to millions of dollars in annual expenditure. Traditionally, nuclear plant managers and operators were primarily focused on optimizing plant operating parameters, such as minimizing the duration of major maintenance and refuel outages and achieving high availability factors, and, to a lesser extent, were concerned about efficient inventory management. Generally, materials and supplies were expected to be available whenever required and in plentiful supply. Prior to the onset of electricity deregulation and the renewed emphasis on efficient electricity production, it was not unusual to have large nuclear power plants' inventory levels exceeding $40–50 million per unit.

With deregulation and electricity price competition, the requirement for the careful management and tracking of nuclear plant materials and supplies inventories, as well as the maintenance of high inventory turnover rates, will be essential for efficient and competitive nuclear electricity production.

Definitions:

Inventory level ($) is the total value of the material and supplies inventory for a nuclear unit at a given point in time. It is consistent with NEPIS Account A1410 and expressed in dollars. It should be noted that fuel and heavy water values are not included.

Calculation: N/A

4.2.11. **Indirect cost** (c/kW·h)

Purpose:

Indirect cost, sometimes referred to as indirect non-fuel O&M cost or A&G expenses, is a significant component of the total cost of producing electricity on a cents per kilowatt-hour or mills per kilowatt-hour basis. For example, in the USA indirect costs often represent more than 20% of the total direct O&M expenditures of a nuclear unit. Expressed differently, on a cents per kilowatt-hour basis, total nuclear indirect O&M costs can be as much as 0.5 c/kW·h based on industry average annual capacity factors. Typically, a substantial portion, usually in excess of 30–40% of nuclear indirect expenditures, is associated with the utility staff supporting the O&M of a nuclear facility. These costs typically include various medical, severance and pension benefits provided to the utility's nuclear staff. Although the extent to which these benefits are provided may vary dramatically from one country or region to another, as with direct nuclear O&M, the tracking and control of nuclear indirect costs can significantly impact the earnings and profitability of a nuclear generating unit.

Definitions:

Indirect cost (c/kW·h) is defined as the total nuclear indirect cost for a given period divided by the net generation over the same period.

Total indirect cost ($) refers to corporate, non-fuel O&M expenses, including labour and materials, relating to a specific nuclear generating facility (plant or unit), not directly associated with the on-site O&M of the plant or unit, including liability, property and replacement power insurance, cost of pensions, medical benefits and payroll tax, and corporate A&G expenses which would be allocated to 'nuclear', such as legal, human resources, management functions, accounting, etc. It is the cost consistent with NEPIS Account 2500 and expressed in dollars.

Net generation (MW·h) is the electrical energy produced during the time period as measured at the unit outlet terminals, i.e. after deduction of the electrical energy taken by the unit auxiliaries and the losses in transformers that are considered integral parts of the unit. It is the net generation consistent with NEPIS Account A1650.

Calculation:

$$\text{indirect cost (c/kW}\cdot\text{h)} = \frac{\text{total nuclear indirect cost (\$}\times 1000)\times 100}{\text{net generation (MW}\cdot\text{h)}}$$

4.2.12. Energy price ($/MW·h)

Purpose:

Energy price, in essence the market price of electricity, is the most sensitive economic variable used in determining the ultimate profitability and competitiveness of a nuclear power plant operating in a deregulated market. Although it is one of the major variables over which the management of a nuclear facility has least control, it also affords significant financial opportunity. All other factors being constant, small variations in the price of electricity, in the order of $1/MW·h, can dramatically impact revenues and earnings for a nuclear unit, to the extent of millions of dollars annually.

A keen awareness of the drivers that affect fluctuations in the market price of electrical energy will enable nuclear plant managements to take the greatest advantage of the opportunities to optimize revenues, avoid risks and maximize plant net earnings. Energy price, as a major economic performance indicator, will significantly influence management decisions and strategy development concerning the timing and duration of planned nuclear outages and the risk management associated with the sale of nuclear generation by either power purchase agreements, bilateral contracts or spot market bidding arrangements.

Definitions:

Energy price ($/MW·h) is the generation weighted average price of the electricity sold over a given period.

Generation weighted average price ($/MW·h) is the equivalent price of all energy sold during the period.

Calculation:

Generation weighted average price sample calculation

Assume for a period: 1 000 000 MW·h (G1) sold @ \$30/MW·h (P1)

1 500 000 MW·h (G2) sold @ \$35/MW·h (P2)

2 000 000 MW·h (G3) sold @ \$50/MW·h (P3)

Total generation sold = 4 500 000 MW·h

Average (mean) price = \$38.33/MW·h

$$\text{generation weighted average price} = \frac{(G1 \times P1) + (G2 \times P2) + (G3 \times P3)}{\text{total generation}}$$

$$= \$40.55/\text{MW·h}$$

4.2.13. Return on investment

Purpose:

Financial performance measures such as return on investment and return on equity are the quintessential key measures of profitability and efficient cost of capital in operating a business enterprise. As such, their application and usefulness is not new to the electric utility industry. As a matter of fact, the return components of the traditional cost of service revenue methodologies and the ultimate determination of electric utility weighted cost of capital are almost unique to regulated electricity monopolies. Under typical regulation, appropriate levels of return are frequently politically determined, commensurate only with evaluated low levels of risk and, all too often, are essentially assured to utility investors.

In the nuclear power industry, the complex process of evaluating capital investments for corporate approval and ultimately for recovery in electricity rates is further exacerbated by the overwhelming obvious imperative for continuous safety upgrades and reliability improvements. What is today and will continue to be a challenge for the nuclear industry is the recognition that sound, traditional business practices, along with superior business literacy, must be embraced and successfully applied at the nuclear power plant level by nuclear plant managers and operators if nuclear electricity is to remain a competitive option in the future. The application of fundamental economic principles and key financial metrics must be as commonplace and integral to the decision making process as are those of safety and reliability. Under deregulation, the application of traditional profit/loss or income statement analysis, applied to individual nuclear power plants or units, as well as at the generating company or corporate level, will become increasingly evident and necessary. Financial performance measures such as return on investment and return on equity will become the principal metrics for these purposes.

Definitions:

Return on investment, expressed as a percentage, is defined as the profit or earnings after tax plus interest paid for a given period divided by the average outstanding investment over the same period.

Earnings ($) are net earnings for common shareholders (revenues less operating costs, tax, depreciation and interest) for a given period.

Interest on debt ($) is the return on the average long standing debt for a given period.

Average outstanding investment ($) is the total investment value of the unit (less depreciation) at the beginning of the period plus the total investment value (less depreciation) of the unit at the end of the period divided by two. It is consistent with NEPIS Accounts A1800, A1810 and A1820 and expressed in dollars converted at the exchange rate prevailing in the year of investment in the plant.

Calculation:

$$\text{return on investment (\%)} = \frac{\text{total return (earnings + interest on debt) (\$)}}{\text{average outstanding investment (\$)}}$$

4.2.14. Return on equity

Purpose:

Financial performance measures such as return on investment and return on equity are the quintessential key measures of profitability and efficient cost of capital used in operating a business enterprise. As such, their application and usefulness is not new to the electric utility industry. As a matter of fact, the return components of the traditional cost of service revenue methodologies and the ultimate determination of electric utility weighted cost of capital are almost unique to regulated electric monopolies. Under typical regulation, appropriate levels of return are frequently politically determined, commensurate only with evaluated low levels of risk, and all too often are essentially assured to utility investors.

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Definitions:

Return on equity, expressed as a percentage, is defined as the profit or earnings after tax for a given period divided by the average outstanding equity investment over the same period.

Earnings ($) are net earnings for common shareholders (revenues less operating costs, tax, depreciation and interest).

Average outstanding equity investment ($) is the total equity investment value of the unit (less depreciation) at the beginning of the period plus the total equity investment value (less depreciation) of the unit at the end of the period divided by two. It is consistent with NEPIS Accounts A1800, A1810 and A1820 and expressed in dollars converted at the exchange rate prevailing in the year of investment in the plant.

Calculation:

$$\text{return on equity (\%)} = \frac{\text{earnings (\$)}}{\text{average outstanding equity investment (\$)}}$$

4.2.15. Maintenance backlog

Purpose:

The maintenance backlog is the method used to determine the number of backlog activities that the nuclear utility should have carried out but which for some reason have been delayed. Reasons could include lack of human resources, lack of equipment or materials, etc. This indicator could be collected for preventive and corrective maintenance separately, depending on the work request form. For corrective maintenance, the work request activity is included in the corrective maintenance programme that would establish priority, i.e. immediate, within 24 hours, within two weeks or under the normal maintenance programme (six weeks). For preventive maintenance, it reflects the number of work requests not executed or deferred.

Definitions:

Maintenance backlog is defined as the total number of maintenance activities backlogged for a given period pending execution, expressed as the number of work requests. It could be for corrective or preventive maintenance.

Calculation: N/A

5. STRATEGIES FOR IMPROVEMENT

5.1. BASIS FOR STRATEGIES

The performance measures included in this report are not proposed as a comprehensive, all-inclusive set of measures intended to represent all nuclear economic requirements throughout the world. They represent the starting point from which to identify key economic measures for nuclear power plants operating under a diversity of financial regulatory and business requirements. These indicators were founded on the opinions and practices of the nuclear power industry and the financial community participated in the research. Their selection is representative of the opinions, experience and business requirements of the countries and their representatives that participated in the research project to develop them.

In this regard, this section proposes a number of improvement strategies to support the continued selection, development and implementation of standard nuclear economic performance measures for broader application throughout the world.

In reviewing the proposed strategies, consideration should be given to the following critical factors observed during the process of developing economic measures included in this report:

(a) The extent and nature of electric power deregulation as well as the business requirements of generating companies vary dramatically across various regions worldwide.
(b) The economic life cycle of a nuclear enterprise is extensive. It begins with planning and construction, extending throughout the licence life, including life extension, and concludes with decommissioning. Any evaluation of nuclear economic measures should ultimately address all phases of this cycle.
(c) Knowledge of the fundamentals of business literacy among management and operators of nuclear power facilities is diverse. Traditional focus and training development have been on achievement in areas of safety and operational reliability.
(d) As deregulation and privatization continue to evolve, the nuclear power industry has continued to emphasize the need for effective financial/economic performance measures. Other nuclear industry organizations are also in the process of evaluating these requirements.

5.2. STRATEGIES

5.2.1. Economic performance indicator process

Clearly, a major consideration in choosing economic indicators is the extent to which a particular indicator is universally applicable, in light of the differing financial requirements and the nature of global deregulation. This project performed such validation exercises on utilities or operators in eight countries: Brazil, Czech Republic, Hungary, India, Mexico, Slovakia, Ukraine and the USA. A formal process to facilitate the collection of data and publication of results was developed, tested and implemented (see Annexes II, III and IV).

Other countries and the international nuclear industry could also benefit from a set of standard economic indicators. Prior to continuing with the development of a more comprehensive standardized set of economic indicators for broader application worldwide, the indicators currently proposed in this report need to be widely tested through benchmarking processes.

5.2.2. Business literacy development

The sound understanding and effective application of fundamental business principles will be required by the nuclear industry as regulation and competition shift the focus of nuclear plant management to emphasize economic as well as safety and reliability strategies. It is important to develop and enhance the knowledge of fundamental business principles among nuclear power plant managements and operators throughout the world.

5.2.3. IAEA NEPIS enhancements

In its current state, some information included in the NEPIS is applicable and consistent with the definitions of the economic performance measures proposed in this report. Since the NEPIS data acquisition system has been formally implemented for a number of years, it could provide an ideal vehicle for obtaining the additional data required to update all economic indicators.

As an example, the NEPIS enhancement to include nuclear staffing data similar to those in the EUCG Nuclear Integrated Information Database would be valuable. Proposed modifications can be accomplished efficiently through the continuing affiliation with the EUCG Nuclear Committee to take the greatest advantage of a similar database and software developed previously.

5.2.4. Continued development of economic measures

As deregulation and privatization of the electric power industry continue to evolve, requirements for additional market and plant level economic indicators, beyond those proposed in this report, should continue to be investigated. For example, economic measures relating to the financial health and valuation of a nuclear enterprise may require additional consideration.

In addition to the identification of specific indicators, consideration should be given to other approaches, including the development of an economic performance index (similar to the INPO/WANO performance index), a standard nuclear plant income statement (see example in Annex V) and other leading factors or indicators which may correlate to nuclear plant economic performance.

Other nuclear industry organizations have evaluated the topic of financial performance indicators in the regulated markets. For example, the Electric Power Research Institute (EPRI) in conjunction with the Nuclear Energy Institute and the EUCG Nuclear Committee recently published a document on this subject. Although their report appears to focus solely on the US electricity market, several findings and proposed economic measures may be applicable to broader world markets.

Further, considering that the EPRI report findings are limited to broad definitions and general applications of proposed indicators, the detailed models for defining and updating economic indicators proposed in this report could be shared with these organizations.

Annex I

NATIONAL APPROACHES TO ECONOMIC PERFORMANCE

I–1. BRAZIL

I–1.1. Economic and energy scenarios

The population of Brazil was about 170 million in 2001. Currently, about 80% of the people live in urban areas. Many migrants to the cities take up residence in favelas or shantytowns, on the edge of urban areas. The urban poverty and unemployment that accompany swift urbanization are aggravated by a fast population growth rate.

In 2001, Brazil's gross domestic product (GDP) was $567 billion, with a per capita GDP of $3494 and an annual growth rate of 4.2% during the period 1980–2001. Electrical energy consumption in Brazil reached 347 TW·h in 2002.

The Brazilian electrical system comprises a fairly large grid, covering a very large territory, with a current installed capacity of around 75 GW. The electricity generated is predominantly hydroelectric. There has been great pressure in the last years to aggregate new energy to the grid in order to meet an increase in demand, thus requiring heavy investment in the generation, transmission and distribution of electricity. Under these circumstances it will be possible for nuclear power to participate in this market and to overcome the main obstacles to its growth in the electrical matrix.

The main characteristics of the Brazilian electric system are:

(a) Mainly relies on hydroelectric plants (approximately 85% in 2002);
(b) Demand for electricity is highly concentrated in the southeast region of the country, mainly in large cities such as São Paulo and Rio de Janeiro;
(c) The largest load centres are distant from the most significant hydroelectric plants, requiring the transport of large energy blocks over great distances;
(d) The number of residential consumers has increased steadily, requiring connection to the distribution grid of 2 million new homes per year.

There are two nuclear units in operation: Angra 1 (657 MW(e) PWR) which went into commercial operation in January 1985 and Angra 2 (1350 MW(e) PWR) which started commercial operation in February 2001. Both are located in the Angra dos Reis region, 130 km from Rio de Janeiro and

220 km from São Paulo. A third PWR plant, Angra 3, similar to the second unit, is under construction at the same site.

Although the capacity of the two nuclear plants represents less than 3% of the total installed capacity in Brazil, they produced, in 2002, close to 14 000 GW·h, corresponding to 4% of the total national electricity production and approximately 12% of the maximum storage capacity of the equivalent water reservoir in the southeast and central–west regions.

I–1.2. Electricity market status: Regulation, deregulation, privatization

The Brazilian electricity sector is facing a restructuring that involves the following institutional aspects:

(a) Creation of the wholesale energy market (MAE), with the definition of new agents, their relationships, commercialization rules at the supply level and measures to ensure competition to be followed by companies operating in more than one of these segments: generation, transmission, commercialization and distribution. All generators with installed capacity above 50 MW and all distribution/retailers with annual sales in excess of 100 GW·h were required to join the MAE. Free consumers are entitled to join. Large consumers (over 3 MW) are free to choose their suppliers.

(b) Implementation of open access to the transmission and distribution networks, including non-captive consumers to their suppliers and the remaining systems agents.

(c) Establishment of a regulatory agency — the National Electric Energy Agency.

(d) Creation of the National Electric System Operator (ONS) and the definition of responsibilities in regard to generation supply and basic transmission networks.

(e) Restructuring of ELETROBRÁS post-privatization. ELETROBRÁS retained a minority interest in the privatized companies, its 50% stake in Itaipu and ownership of the nuclear power plants.

The central feature of this trading market model was the creation of the ONS, an independent company responsible for the operational planning, scheduling, dispatch and market price calculation. The trading market model has been gradually implemented since 2000, when the functions of GCOI and CCON were transferred to ONS and the MAE was established.

The relationship between generators and consumers/distributors is currently controlled by bilateral contracts that represent 90% of the whole market, with just 10% sold under free conditions, owing to institutional restrictions. Nuclear is included in this form of contract in the same way as Itaipu. Since January 2003, 25% of the energy has been subject to free negotiation between generators and distributors, without tariff regulation. ELETROBRÁS currently commercializes the energy from Itaipu and is now proposing to commercialize the energy from the nuclear plants.

The current challenge for nuclear energy in Brazil is to compete in the new market, in which the tariffs of the four federal supplier companies in 2002 stayed around 20 \$/MW·h for the generation services. The generation costs of hydroelectric plants are currently about 15 \$/MW·h compared with nuclear's 27 \$/MW·h. It is a question of competitiveness. In the long term, nuclear energy will be necessary in the Brazilian energy mix. It is not known how long this period will be or whether Brazil will be able to implement its nuclear power programme in the future.

I–2. CZECH REPUBLIC

I–2.1. Economic and energy scenarios

The Czech Republic covers an area of 78 864 km^2 and has a population of 10.3 million according to a 2001 census. The population is slightly declining.

The development of the Czech economy is particularly characterized by the economic reform undertaken since 1989. In 2001, Czech GDP was \$47.5 billion and the per capita GDP was \$4629. At present, economic growth is slowly increasing.

Both primary and final energy consumption decreased between 1990 and 2000. The decrease in the final energy consumption is larger than that of primary energy.

The structure of consumption has changed even more substantially since 1990. In 2000, the structure of primary energy consumption was coal (54%), oil (19%) and natural gas (19%). Nuclear energy accounted for 8%.

Brown coal (lignite) remains the main source of primary energy. Regardless of the declining trend in its usage, coal will remain significantly important in the future and currently represents about 40% of the primary energy sources. The contributions from commercial renewable sources and hydroelectric power are almost negligible. Coal is exported and almost all oil and natural gas are imported.

The energy sources for electricity production have been quite stable for several years. This is mainly due to the Dukovany nuclear power station (four PWR units, 440 MW(e)), which has been in full operation since 1987, and the main hydroelectric potential, which cannot be increased further. The second

Czech nuclear power plant is at Temelín (two PWR units, 981 MW(e)) and this has been in operation since 2002. In 2002, fossil fuel (mostly coal) plants accounted for 78% of total electricity generation, nuclear power (Dukovany and Temelín) 19% and hydroelectric plants only 3%. With the commercial operation of Temelín, nuclear power will represent approximately 40% of electricity production in the Czech Republic.

I–2.2. Electricity market status: Regulation, deregulation and privatization

Almost 70% of the electricity production is provided by CEZ a.s., the joint stock company which is the owner of 10 coal fired power plants, the two nuclear power plants at Dukovany and Temelín, several large hydroelectric power plants and two pumped storage hydroelectric power plants (13 in total), three wind power plants and one solar power station. The remainder is provided by plants owned by independent producers (e.g. Elektrárna Opatovice a.s., Elektrárna Kolín a.s.), industry self-producers, local heat producers (cogeneration) and by eight regional utilities (0.5%). CEPS a.s., a company owned jointly by CEZ and the Czech State, owns the 'backbone' high voltage power transmission system (400 kV and 220 kV lines) and dispatching centre.

By 2002, CEZ became one of the major electricity exporters in Europe; the overall export was 16 580 GW·h.

CEZ is 68% owned by the National Property Fund of the Czech Republic. Other shares are in possession of foreign and domestic institutional investors (17%), custodians (11%) and individuals (4%).

Eight electrical power distribution companies (utilities) distribute electricity. The utilities can buy electricity from small hydroelectric and wind plants. Five regional distribution companies were sold by the State to CEZ in April 2003.

Act No. 458/2000 Coll. (Energy Act) regulates the business in the electrical power sector. According to the Energy Act, electricity generation, distribution, transmission and trading are subject to licensing.

As of 1 January 2002, in accordance with the Energy Act, the Czech Republic's electricity market was liberalized. The market for electricity is based on regulated access to both the transmission and distribution grids.

Also effective 1 January 2002, the first group of customers (those with an annual consumption in excess of 40 GW·h) was given eligible customer status, with the right to access the transmission and distribution grids and with the right to choose their electricity supplier. As of 1 January 2002, the only prices regulated by the Energy Regulatory Office are those for protected customers and those for transmission and distribution. The electricity market will be completely liberalized for all final customers by 2006.

The Energy Regulatory Office defined in the Energy Act is a separate State organization responsible to the Prime Minister and established as the administrator office to exercise regulation in the energy sector. Its operating costs are covered by the State budget approved every year by Parliament. The general mission of the Energy Regulatory Office is to support economic competition and protect consumers' interests in the energy sector, aiming to meet all reasonable requirements for energy supply.

The first attempt at CEZ privatization was cancelled in 2001 because bidders offered a lower price than that acceptable to the State. Any future privatization attempt has to be approved by the Czech Government.

I–2.3. Measuring and monitoring economic performance

The Czech power sector is in a period of transition to a liberalized electricity market. All participants in this market have to be prepared for change and this will affect nuclear power plants as well as other market players. Nuclear power plants' increasing share of the whole electricity market in the Czech Republic and its increasing liberalization require a considerable degree of preparedness. On the one side are concerns regarding nuclear safety and technical availability, on the other the competitive generation of electricity in nuclear power plants.

During the 1990s, many measures were undertaken to improve safety and technical availability at the Dukovany plant. All these measures were carried out against a background of uncertainty regarding future market liberalization. All investments and major maintenance action were checked for their effectiveness. Tenders were used to select the best supplier from the point of view of technical as well as economic considerations (including influence on generation cost). An extensive programme of maintenance optimization was started in the mid-1990s as well as a programme for optimization of the fuel cycle. The result of all these measures was that generation costs were stabilized in the second part of the decade. Experiences from this period will be shared with the Temelín nuclear power plant.

For monitoring the effectiveness of production, the following basic indicators are used:

(a) Electricity supply fed into the grid (MW·h).
(b) Unit cost of delivered electricity (specific production cost in Czech crown/MW·h).
(c) Available capacity (MW).

(d) Costs, total and itemized, of consumption of materials, fuel and energy; repair and maintenance; wages; depreciation; and contributions to the State Fund for Decommissioning of Nuclear Power Installations and other operating costs.

As an aid to managers, a system incorporating technical and economic indicators is used for monitoring operations. This system assists the performance improvement programmes at both nuclear power plants.

I–3. HUNGARY

I–3.1. Economic and energy scenarios

Hungary is a landlocked central European country covering an area of 93 032 km^2. In 2000, its population numbered about 10 million and the population density is 108/km^2.

Hungary is still in the midst of a difficult transition from a centralized to a market economy. Its economic reforms initiated during the communist era gave it a head start in this process, particularly in terms of attracting foreign investors. Although the privatization process has lagged, overall, about half of GDP now originates in the private sector. The Hungarian economy has undergone a dramatic transformation since 1995 and as a result the GDP per employed person has shown continuous improvement in the course of the past few years.

Hungary has various energy resources, but relies mainly on coal (including lignite). In recent years, Hungary annually produced about 20–22 million tonnes of coal, including 5–6 million tonnes of poor quality lignite. Hungary also produces oil, although current annual production of approximately 2 million tonnes satisfies less than a quarter of domestic demand and is decreasing. About 6 billion m^3/a of natural gas is produced, supplying roughly half of the total demand. Gas production is also decreasing.

Total installed electric capacity is more than 7000 MW(e) of which 74% is fossil fired, 25% nuclear and 0.7% hydroelectric. Hungary joined the electric network of Western Europe (UCPTE) in 1993.

The only nuclear power plant in the country is located about 5 km south of the town of Paks, on the right bank of the River Danube. Since 1987, four reactors have been generating electricity for the Hungarian grid. The installed capacity of each reactor is 440 MW(e). Both the technical as well as the economic experience gained at the Paks plant have so far been very satisfactory. The plant runs in base load and sells electricity to the Hungarian Power

Company (MVM Rt) under long term contract. The average load factor has remained fairly constant (80.4–94.1%) for several years and is above the international average. Nuclear electricity generation amounts to about 14–15 TW·h/a and this represents about 40% of total electricity generation.

State Asset Management owns MVM Rt and is responsible for long term strategic asset administration, maintenance of the State and implementation of the national asset policy guidelines. MVM Rt is responsible for wholesale trading, import/export, the basic network, system dispatch and system development. There are four different company groups in the ownership structure belonging to MVM Rt:

(1) Power plants;
(2) Power plants with coal mines;
(3) Distribution companies;
(4) National Grid Operating Company.

The national grid is a part of the former Comecon power system, having 750 kV and 400 kV interconnection lines with neighbouring countries. During the 1990s, a major privatization programme was undertaken in the Hungarian electrical energy sector. The majority shares of most of the electric power distribution companies, gas distribution companies, gas based power generating companies and coal fired power generating companies have been sold to foreign strategic investors.

A final decision has not yet been taken on the privatization of MVM Rt, which is joint owner, along with the Maintenance Company (OVIT Rt), of the national long distance grid and the Paks nuclear power plant. In order to comply with EU Directive 96192 on the internal market for electricity, the Hungarian electricity market needs to undergo some more structural change if effective competition is to be introduced. The major Hungarian energy policy directives approved by Parliament are the following:

(a) Maintaining and increasing energy supply stability;
(b) Increasing energy efficiency and the role of energy conservation, thereby improving the competitiveness of the Hungarian economy;
(c) Establishing a market conforming to organizational, economic and legal criteria;
(d) Enforcing environmental protection aspects;
(e) Promoting European integration in the energy sector.

In accordance with the new Government programme, the Ministry of Economic Affairs elaborated the Basic Principles of State Energy Policy and a

New Business Model. This document maintains the main objectives and reflects on the new ownership situation after privatization and the EU liberalization directives and sets out practical approaches to accomplish the required adaptation, including responsibilities and deadlines.

I–3.2. Electricity market status: Regulation, deregulation and privatization

The majority of the Hungarian power industry has been privatized, with the exeption of the Paks nuclear power plant which is a State owned company. Owing to the strategic importance of nuclear power generation, the maintenance of State control remains a long term objective even in the case of potential partial privatization.

Hungary's EU accession plans have determined the principles of nuclear power plant operation since the mid-1990s. The long term power policy adapted to the European power environment has set out three main directions for the nuclear energy sector:

(1) Implementation of a development/investment programme assuring the nuclear safety and reliability of the power supply of the Paks facility in accordance with international requirements;
(2) Introduction of measures for reducing production costs, maintaining the price level, and enhancing the effectiveness and better use of resources;
(3) Expansion of nuclear electricity generation capacities by a life extension of 20 years and a power upgrade of 8%.

Hungary can expect a transition period of 10–15 years before gaining free access to the competitive market. In the meantime, the full-scale propagation of market conditions and the strengthening of the economy will facilitate the creation of a fully open market. This process will take place in several stages according to the principle of 'progressiveness' in the EU. According to the Directive, in 2005 the EU Member States are to open at least 30% of their electricity markets to their authorized consumers. The market will not be opened in one stage even when all consumers are authorized, since there will always be some consumers incapable of utilizing free access to electricity purchase on the market. Therefore, there will be a long period of coexistence between the free and obligatory elements of electricity supply. The methods of retail price control currently applied in Europe will presumably continue to apply to the latter.

On the opening of the market, a competitive market model will replace the obligatory supply model. The present fixed (series) contracting system will be replaced by a contracting system allowing for optional connections between the market participants. In addition, the natural monopolies' and company owned grids are to be made available to others. According to the pace of market opening, access to the power supply will only be available to producers and authorized consumers on the basis of voluntary commercial agreements made between them. The pace of market opening will be determined at EU level and shall be mutually agreed between the individual States. At the same time, public supply obligations may be devolved to the contractors involved in the power industries of the EU Member States without detriment to the principles of competition, thus also assuring the power supply to non-authorized consumers.

The ratio of the two sectors will change gradually according to the stage of market opening and the will of consumers. The consumers and consumer groups capable and willing to join the competitive market can enter the market economy on request. A former authorized consumer, however, may require a return to the controlled market.

Priorities for the domestic power supply policy of Hungary as an EU Member State can also be determined, such as:

(a) Security of power supply;
(b) Energy efficiency;
(c) Cost effectiveness;
(d) Enforcement of national interests;
(e) Protection of the environment;
(f) Provision of subsidies to those in need.

I–3.3. Measuring and monitoring economic performance

The market changes create a self-evident need for the development of various methods of measurement and qualification that offer appropriate tools to effect the required comparisons and allow prompt representation of information on the power changes. During recent years, varied methods of measurement, reporting and monitoring have been established in accordance with topical objectives, and several international organizations have monitored the changes in the performance, technical and financial indicators of the Paks nuclear power plant and presented these changes in different publications. Within the market environment taking shape in Hungary and in neighbouring countries, the need for a voluntary performance measurement system is becoming inevitable for the representation of the changes against domestic indicators as well as international indicators. The performance indicators shall be simple, easy to survey, accepted throughout the industry and applicable to the given parameter.

To date, the large number of specific performance indicators used at the Paks nuclear power plant is currently being replaced by a smaller number of widely applicable and less complex indicators that provide prompt and useful information for the evaluation of the plant within the market environment. Naturally, an appropriate system of indicators can only be based on the information stored in an adequate background database, with the methodology for the establishment of an integrated management information system to be developed. The necessary conditions are ensured at Paks and the significance of up-to-date performance indicators is increasing with the transition to a liberalized market environment.

Owing to the specific features of the nuclear industry in Hungary, both the power plant indicators and the corporate specific indicators are intended for the same purpose, since the nuclear power plant operates as a single independent production unit. The primary purpose of the indicators for the nuclear power plant is to trace the changes occurring within the plant, to analyse variations in the results in a timely manner and to take corrective measures to make continued plant operation more effective. Special emphasis shall be given to the use of the plant unit level indicators that are suitable for internal performance evaluation purposes, but particularly for performing international comparisons of plant units having similar parameters.

The management of the Paks nuclear facility shares a special responsibility to recognize the need for the development of internationally applicable and acceptable performance indicators and to encourage their application as well as to operate an information system facilitating their standardized use.

I–4. INDIA

I–4.1. Economic and energy scenarios

According to the 2001 census, India's population numbered 1027 million. The estimated growth in population from 1991 to 2001 was at an annual rate of about 2%.

In 1999, India's GDP was $447 billion and the per capita GDP was $448. The annual growth rate averaged 5.4% during the period 1980–1999.

The energy resources are unevenly distributed in the country and are mainly used for power generation, transport, and industrial and domestic use. The hydroelectric potential in the country is estimated at 84 GW(e) (at a 60% load factor). Out of the total potential available as of April 2002, only about 30% has either been developed or is being developed. More than 70% of the total hydroelectric potential in the country is located in the northern and north-eastern regions.

Coal (including lignite), oil and natural gas are used for thermal power generation. As of 1 January 2001, the geological reserves of coal were estimated to be about 221 billion tonnes with proven mineable reserves of 84 billion tonnes. The eastern region accounts for about 70% of the coal resources. Lignite reserves suitable for power generation are estimated at 27.45 billion tonnes and these are being exploited for this purpose in Tamil Nadu and Gujarat. Recoverable reserves of crude oil are placed at 600 million tonnes and of natural gas at 650 billion cubic metres.

The estimated potential for non-conventional renewable energy resources are: 45 000 MW for wind energy, 15 000 MW for small hydroelectric power plants, 50 000 MW for ocean thermal, 19 500 MW for biomass and 35 000 MW/thousand km^2 from solar. This is in addition to potential for biogas plants and efficient wood stoves.

The per capita energy consumption increased from 3 GJ in 1960 to nearly 16 GJ in 2000. During the same period the per capita electricity generation increased significantly from 45 kW·h to 495 kW·h. The total installed electric power capacity of only 5.58 GW(e) in 1960 grew to about 104.94 GW(e) in 2001–2002. The major contribution to electricity generation during 2001–2002 in energy terms (from utilities) came from thermal power (82%), hydroelectric (14.3%) and nuclear (3.7%). During the period 1980–2000 the growth rate of electricity generation in energy terms was more than the growth rate in capacity addition indicating improved capacity utilization.

I–4.2. Electricity market status: Regulation, deregulation and privatization

The structure of the electricity sector derives its character and composition from the Indian constitution and is defined by the electricity acts. The responsibility for electric power production and supply is vested mainly in the central and the state governments.

India is divided into five electricity regions, namely, northern, north-eastern, eastern, western and southern. A regional electricity board is constituted for each region, and this essentially provides guidelines for operation of the grid and coordinates exchanges of power between states and regions. The regional electricity board also reviews progress of schemes and plans generation schedules.

The Power Grid Corporation of India Limited (PGCIL) has been established by the central Government with a mandate to establish and operate regional and national power grids to facilitate the economic transfer of power within and across the regions with reliability and security and according to sound commercial principles. All transmission facilities originally under central sector organizations have been transferred to PGCIL. State electricity boards also establish the transmission schemes for delivering power generated by the power stations they set up.

With the amendment of the electricity laws, transmission activity has been given an independent status and the concept of central and state transmission utilities has been introduced. While PGCIL has been notified as the central transmission utility, the state electricity boards or their successor state transmission companies would be state transmission utilities, which would be Government enterprises. It is proposed that participation of the private sector in the area of transmission be limited to construction and maintenance of transmission lines for operation under the supervision of central and state transmission utilities.

In 1991, the Electricity Supply Act (1948) was amended to provide a legal framework for facilitating greater investment by private enterprise in the electricity sector. The Government has introduced incentives from time to time and a body, the Investment Promotion Council, has been set up to further this aim. The response from the private sector has been encouraging.

Nuclear power generation is governed by the Atomic Energy Act and, along with related fuel cycle activities, remains under Government control. The Nuclear Power Corporation of India, a wholly owned subsidiary of the Government and the Department of Atomic Energy, is responsible for setting up nuclear power projects. The other related fuel cycle (both front end and back end) activities are carried out by the different units of the Government and the Department of Atomic Energy. Currently, there is no equity participation by the private sector in the area of nuclear power generation, although the possibility of establishing joint ventures with the private sector is being explored. This is being considered essentially with a view to attracting investment in the nuclear power sector for capacity addition. The nuclear power plants currently in operation are generating electricity at competitive tariffs. Measures to reduce the construction time of nuclear power plants and increase standardization are being taken to strengthen the economic competitiveness of nuclear power.

I–4.3. Measuring and monitoring economic performance

The Indian power sector is currently in a state of transition, moving from a completely regulated market to a completely deregulated one. It is expected that this transition will take quite sometime to complete, as it will be necessary to bridge the substantial gap between electricity supply and demand in the country as a prerequisite to adopting a completely deregulated market. The contribution of nuclear power currently accounts for about 3% of the electricity supply in the country, which is expected to increase in the years to come. With the liberalization of the power sector, there is growing pressure on all generating companies to optimize the tariff for power. With the existing tariff mechanism applicable to nuclear power, the company engaged in generation of nuclear power in India is able to make good profits from its operation provided that the nuclear power plants operate at a high plant load factor. However, there are pressures to reduce the tariff for nuclear power. Currently, the strategy adopted to optimize the cost of nuclear power involves controlling the capital costs of new projects as well as improving the plant load factor of the nuclear power plants.

Economic performance indicators other than the safety related performance indicators pertaining to the operation of the nuclear power station being monitored are shown in Table I–1.

The performance indicators, namely, capacity factor, availability factor and net generation, are all indirect economic indicators of revenue generation. Cost of heavy water replenished is an element of cost of operation, which varies from plant to plant depending on the efficiency of management of heavy water. Monitoring heavy water loss and controlling it will help reduce the operational cost. The O&M cost and fuel cost are significant elements of operational cost and are monitored with a view to optimizing them and thereby reducing the overall costs. Net profit before tax will directly indicate the earnings of the station after meeting all costs.

TABLE I–1. ECONOMIC PERFORMANCE INDICATORS

Performance indicator	Unit of measure
O&M cost	\$, $\$ \times 10^3$
Capacity factor	%
Availability factor	%
Net generation	GW·h
Heavy water cost	$\$ \times 10^3$
Fuel cost	\$, $\$ \times 10^3$, $\$ \times 10^6$
Net profit before cost	$\$ \times 10^3$

I–5. MEXICO

I–5.1. Economic and energy scenarios

Mexico covers an area of 1 958 200 km^2. In 2001, the Mexican population reached 100.4 million, corresponding to a population density of 51.3/km^2. During the period 1980–2001 the population growth rate averaged 1.9%.

The GDP in 1999 was $346 billion (constant 1990 dollars) and its annual growth rate over the last 5 years has been about 5%.

Mexico has abundant oil, gas, coal and hydroelectric resources. The total proven reserves of liquid hydrocarbons amount to 63 220 million barrels, equivalent to 48 years' supply at the current rate of production. Mexico is not only energy self-sufficient, but is also a net exporter of energy. However, it is highly dependent on hydrocarbons. Almost all the energy exported is in the form of crude oil and about 90% of the energy used in the country comes from oil and gas, only about 5% comes from hydroelectric. In order to alleviate this situation, Mexico has recently developed other forms of energy such as geothermal, coal and, since 1990, nuclear energy.

From 1980 to 2001, electricity generation grew 5.8% annually on average, going from 66 950 GW·h in 1980 to 221 770 GW·h in 2001 (Table 6). The average load factors were: 52% for thermal plants, 35% for hydroelectric and 68% for nuclear. Table 7 shows the energy related ratios from EEDB.

I–5.2. Electricity market status: Regulation, deregulation and privatization

Owing to historical reasons, the electricity service is provided by two governmental organizations: Central Light and Power, which serves the Mexico City metropolitan area and some parts of the states of Morelos, Hidalgo, Puebla and Tlaxcala; and the Federal Electricity Commission (CFE) which serves the rest of the country.

Almost all the generation is provided by CFE; Central Light and Power generates only a small fraction of Mexico's requirements. The peninsula of Baja California has two small independent systems; the northern one is interconnected to the USA. The rest of the country is served by an integrated system, which is controlled by CFE.

Only about 6.5% of the total generation of the country is provided by private industry for its own consumption. In the past, the generation and distribution of electricity has, by law, rested in the hands of the Government. However, recent law modifications allow the generation of electricity by the private sector and promote the use of cogeneration.

Electricity demand is expected to grow at a rate of 6.1% annually for the 10 year period starting 1999, requiring for the same period an additional capacity of 22 248 MW. This expansion rate, the largest in the country's history, will represent an opportunity for private investment. Owing to a lack of public funds in the last few years, a large part of the added capacity has been possible through private investment in the form of IPP and 'build, operate, own and transfer' schemes, and this participation is likely to continue in the future. Transmission and distribution will continue to be the responsibility of the Government.

I–6. SLOVAKIA

I–6.1. Economic and energy scenarios

The size of the Slovak Republic is 49 036 km^2. In 2000, there were about 5.4 millions inhabitants and the population density was 110/km^2.

In 2000, the GDP decreased to \$19.7 billion compared with \$21.3 billion in 1998.

Slovakia has only limited domestic energy resources, i.e. lignite, oil, natural gas and renewable resources. The energy potential of renewable resources in Slovakia represents approximately 5% of the total annual consumption of primary energy resources.

In 2000, the electricity production from Slovak Electric was 26.3 TW·h (about 85%) and from other producers 4.6 TW·h (15%). The latter group consists mainly of energy generators in factories (car producers). The development of electricity production and consumption is given in Table 8. Table 9 shows the installed electrical capacity.

I–6.2. Electricity market status: Regulation, deregulation and privatization

The dominant producer of electricity in Slovakia is Slovak Electric, which is owned by the National Property Fund.

About 90% of the distribution and sale of electricity are done by regional energy enterprises. The power grid operates within the framework of the Central Regional Net (Czech Republic, Hungary, Poland and Slovakia). In October 1995, a long term trial test of the joint operation with the UCPTE started.

Another important measure related to the nuclear power sector is the Government decree on the closure of the two oldest units at the Bohunice V-1 nuclear power plant in 2006 and 2008, respectively. By implementing a programme of modernization and safety upgrading of the Bohunice V-2 nuclear power plant, extension of the V-2 design lifetime will be enabled and the high level of safety maintained. The decision on the completion of Mochovce units 3 and 4 will depend on any interest shown by a strategic partner, as no guaranty of the State is possible.

It is expected that a major part of the increase in electricity demand will be covered by developing the production of independent generators, mainly based on the steam–gas cycle.

I–7. UKRAINE

I–7.1. Economic and energy scenarios

The total area of Ukraine is 603 700 km^2. The population is about 50.1 million and the population density is 83/km^2. In 2001, Ukraine’s GDP was $37.5 billion, with a per capita GDP of $772.

Among the primary energy sources used worldwide — oil, coal, gas and uranium — Ukraine possesses sufficient reserves of only two of them: coal and uranium. The coal industry is based on coal reserves sufficient to cover Ukraine’s needs for the next 200–300 years. As a consequence, coal is forecast as continuing to play a leading role in the future of Ukraine’s energy sector.

Notwithstanding this, more than 40% of the electricity generated in Ukraine is produced by nuclear power plants, but only 30% of the raw components (natural uranium concentrate) required for nuclear fuel manufacture is produced domestically. However, Ukraine has the capability to provide national nuclear power plants with domestic raw materials as its total uranium reserves place it in the top ten countries. The majority of its reserves have been delineated and this should aid their commercial extraction.

By year-end 2001, the gross installed capacity of all electric power plants was 52.8 GW(e), with thermal power plants supplying 36.3 GW(e) (69%), nuclear power plants 11.8 GW(e) (22%) and hydroelectric power plants 4.7 GW(e) (9%).

Total electricity production in 2001 was 173 TW·h (thermal (49%), nuclear (44%), hydroelectric (7%)). Maximum electricity production of 298.5 TW·h was attained in 1990, one year before the Soviet Union ceased to exist. The electricity consumption decreased from more that 5762 kW·h per capita in 1990 to less than 2790 kW·h per capita in 2001. Electricity exports were 2.6 TW·h in 2001, compared with 43.8 TW·h in 1990. Total consumption was 136 TW·h in 2001.

I–7.2. Electricity market status: Regulation, deregulation and privatization

Since 1991, electricity generation in Ukraine has been achieved against a background of political and economic reforms. Reduction of fixed capital and floating stock, consumers' inability to pay, excessive social orientation of price and tariff formation policy of the State are the factors that complicate the market reforms and make adaptation to market conditions more difficult. With the start of reforms in the national economy, the Ministry of Energy developed the principles for reforming the industry and the electricity market. The reforms should ensure the integrity of the unified energy system, competition between generating companies and privatization, and create conditions attractive to investment.

Currently, Ukraine is in transition from a centralized to a market economy. The wholesale electricity market (WEM) is operating now in accordance with the Ukrainian law on the electric power industry issued on 22 June 2000 (No. 1821-III). The WEM's activity is regulated by the rules issued by WEM. The electricity is sold/purchased through agreements concluded by the WEM participants, bilateral electricity contracts concluded within the agreement's frameworks and licences issued by the National Energy Regulatory Commission of Ukraine for electricity production, transmission and supply.

To purchase/sell electricity in WEM it is necessary to hold a licence from the WEM operator and also be party to the WEM framework agreement. WEM is operated by the State enterprise Energy Market, which is subordinated to the Government of Ukraine and governed by a board.

In 2000, the WEM system for payment estimations was changed significantly. From June 2000, the electricity supply companies purchased electricity from the WEM at wholesale prices that were based on the daily kilowatt-hour payment calculation. This transition ensures the balance of payments between generators and suppliers and brings the electricity sale–purchase agreement into conformity with the WEM rules.

For a long time, Ukrainian nuclear power plants have employed different methods of payment. Thus, in 1998 only 7.3% of the total amount of electricity delivered was paid for in cash, the remainder being paid through various offsets and promissory notes. In 2000, the Ukrainian electrical power sector started striving towards receiving payment in cash only. However, all payment types only made up 80.4% of the cost of the electricity.

Thus, the current financial status of nuclear power plants is still far from ideal. Until payment is received for 100% of the electricity supplied, severe problems are likely to remain unresolved, such as a stable and timely maintenance and outage campaign, fresh nuclear fuel supplies and spent fuel withdrawal, and timely wage payment to power plant personnel. The lack of actual earners for settlements with budget and creditors also affects the current situation.

I–8. USA

I–8.1. Economic and energy scenarios

The USA is the world's fourth largest country in terms of area and population. The total area exceeds 9.4 million km^2.

As of 2001, the population was nearly 280 million and the population density is nearly 30/km^2, with 80% living in urban areas.

In 2001, the USA's GDP was $10 082 billion and the per capita GDP was $36 150. An annual growth rate of 6.3% was recorded during the period 1980–2001.

The USA has a market economy. Decisions affecting resources, prices, technology development and other matters pertaining to energy are first made by the private sector within the context of Government regulations. However, through funding of research and development, tax reduction allowances, regulation and other mechanisms, the federal and local governments encourage the development and use of selected energy resources. Favoured resources can vary by jurisdiction. Additional features of Government policy are contained in the Energy Policy Act of 1992. This legislation covers a wide variety of issues, including energy efficiency standards, development of alternative fuels and development of renewable energy.

I–8.2. Electricity market status: Regulation, deregulation and privatization

The structure of the US electric power industry comprises a combination of traditional electric utilities and less traditional electricity producing companies. The electric utilities include investor owned, publicly owned, federal and cooperative firms.

Approximately three quarters of the electricity generated by utilities is generated by investor owned companies. These utilities are, for the most part, franchised monopolies that have an obligation to provide electricity to all customers within a service area. Most provide for the generation, transmission and distribution of electricity, although the distinctions between these services are breaking down as the electricity industry becomes more deregulated. The shares are publicly traded and their areas of business operation are expanding into new ones, sometimes unrelated to the provision of electricity or even energy.

A number of utilities are publicly owned, the most visible example being the federally owned Tennessee Valley Authority (TVA), one of the nation's largest utilities. The TVA is also one of the larger nuclear power generating organizations. Several other federal publicly owned utilities also exist with responsibilities varying widely but often crossing state borders. Publicly owned utilities also include municipal operations, public power districts, irrigation districts and various state organizations. Many municipal electric utilities only distribute power, though some larger ones produce and transmit electricity as well. Federal Government utilities primarily produce electricity and sell it wholesale.

Numerous cooperative electric utilities were established to provide electricity to their members. The Rural Electrification Administration of the US Department of Agriculture was established in 1936 to extend electric service to rural communities and farms. Cooperatives are incorporated under state law and are usually directed by an elected board of directors.

Non-utility power producers include cogenerators, small power producers and IPPs. These lack a designated franchise service area, although they may provide power to specific clients under contract.

IPPs in the USA include wholesale electricity producers that are often unaffiliated with franchised utilities in the area in which they sell power. Utility owned facilities within some jurisdictions may be required to function as if they were IPPs. Thus, distinctions between utility and IPP facilities are often unclear. The Energy Policy Act of 1992 established a new class of IPP – exempt wholesale generators or merchant plants. This act exempted wholesale generators from the corporate and geographic restrictions of earlier legislation. Public utilities are allowed to own IPP facilities through holding companies and have formed subsidiaries to develop and to operate independent power projects throughout the world.

The corporate structure of the industry continues to be dominated by electric utilities, but there has been a shift towards a much more significant role for non-utilities, including affiliates of former utilities. The distinction between utility and non-utility has thus become a very difficult one to make.

I–8.3. Measuring and monitoring economic performance

Economic performance indicators used by US nuclear power plants depend to a large degree on the nature and extent of financial regulation in the states in which they operate (Tables I-2–I-3). In the USA, nuclear plants that continue to operate in regulated monopoly markets tend to focus on the more traditional economic measures that track the expenditure or accumulation of O&M and capital costs and plant production. In regions where wholesale and retail electricity transactions are conducted on open spot markets or through power purchase agreements and competitively bid bilateral contracts, performance measures which seek to optimize the generation of revenues, plant reliability and availability, minimize operating costs and focus on the profitability at the nuclear generating plant level have greater application.

Under financial regulation and oversight, nuclear plants are subject to cost of service regulatory approaches that require minimal attention to operating costs and to a lesser extent investment returns on plant equipment. Plant safety and reliability are most often the primary determinants of management decision making and consequently the focus of key performance measures of success. Although the regulatory process varies from state to state, the fundamental principles that influence and ultimately determine the price of electricity to consumers are generally the same. Utilities' revenue requirements are founded upon complex cost of service formulas which allow the recovery of all 'reasonable' costs, including operating expenses (O&M and fuel costs), tax, depreciation of investments, and which additionally assure a reasonable return on all outstanding investments. Generally, the formal approach or methodology used by electric utility companies and their regulators to determine the revenue requirements and the electricity rates for consumers is referred to as the Minimum Revenue Requirements Discipline. Under this, utility companies and their regulators monitor the companies' operating expenses and investment costs so as to minimize revenues and the electricity rates to consumers. Although operating expenses such as nuclear O&M cost and annual fuel expense are monitored for individual nuclear plants, the investment related costs such as depreciation expense, tax and return are consolidated for generation and other investments and typically monitored at the company or corporate level but not at the nuclear plant or unit level.

Under deregulation and open market pricing of electricity, the business and financial success of operating nuclear plants must be considered to a much greater extent along with the successful achievement of safety and reliability objectives. In developing strategic and operational goals, nuclear plant managers are required to embrace clear and measurable business objectives and goals that not only assure the achievement of safety and reliability but, in addition, eliminate unnecessary costs and identify investment opportunities. These goals must balance operating and safety risk while optimizing plant revenues and earnings and ultimately ensure the profitability of electricity generating facilities. In doing so, it is essential that plant managers articulate

TABLE I–2. US NUCLEAR PLANTS: ECONOMIC PERFORMANCE INDICATORS TYPICALLY MONITORED IN REGULATED MARKETS

Performance indicator	Unit of measure
O&M cost	\$, \$ $\times 10^3$, \$ $\times 10^6$
Capital cost	\$, \$ $\times 10^3$, \$ $\times 10^6$
Capacity factor	%
Net generation	kW·h, MW·h
Staffing level	Number
Fuel cost	\$, \$ $\times 10^3$, \$ $\times 10^6$
Production cost	c/kW·h, mills/kW·h, \$/MW·h

TABLE I–3. US NUCLEAR PLANTS: ECONOMIC PERFORMANCE INDICATORS MONITORED IN DEREGULATED MARKETS

Performance indicator	Unit of measure
O&M cost	\$, \$ $\times 10^3$, \$ $\times 10^6$
Capital cost	\$, \$ $\times 10^3$, \$ $\times 10^6$
Capacity factor	%
Net generation	kW·h, MW·h
Staffing level	Number
Fuel cost	\$, \$ $\times 10^3$, \$ $\times 10^6$
Production cost	c/kW·h, mills/kW·h, \$/MW·h
Going forward cost	c/kW·h, mills/kW·h, \$/MW·h
Revenues	\$, \$ $\times 10^3$, \$ $\times 10^6$
Earnings	\$, \$ $\times 10^3$, \$ $\times 10^6$
Return on investment	%
Return on equity	%

goal achievement through the application of effective, measurable, economic performance indicators.

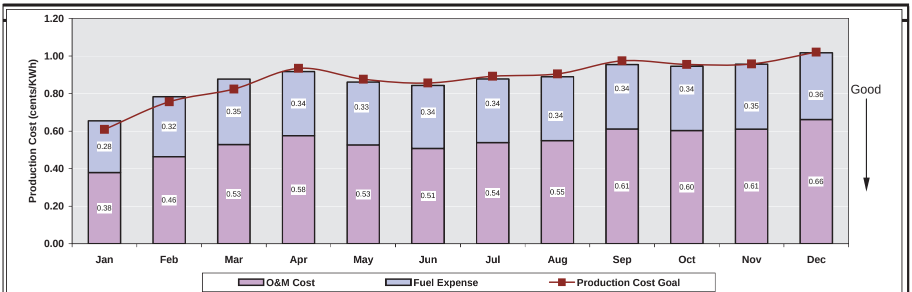
Individual nuclear plants will sell their output competing on electricity price, ultimately to ensure the safe, reliable and economic dispatch of their generation either onto open spot markets or by competitive bidding for bilateral contracts. In either case, an understanding of the operational and economic factors and key measures, which gauge the competitiveness of an individual generating plant, is required. Economic and financial performance indicators are needed for individual plants to measure, evaluate and improve continuously the operating and management processes required to become and remain competitive in open electricity markets.

Annex II*

EXAMPLE INDICATOR CHARTS

The following charts (Figs II-1–II-14) represent a validation of the set of economic performance indicators used by the participating countries. For reasons of confidentiality, plant and country names have been intentionally omitted. However, the data and values are real, representing the actual performance of operating nuclear power plants in these countries.

In applying the performance indicators' formats and definitions to individual countries, care should be taken with the definitions and data table formulas and adjustments made when converting currencies.

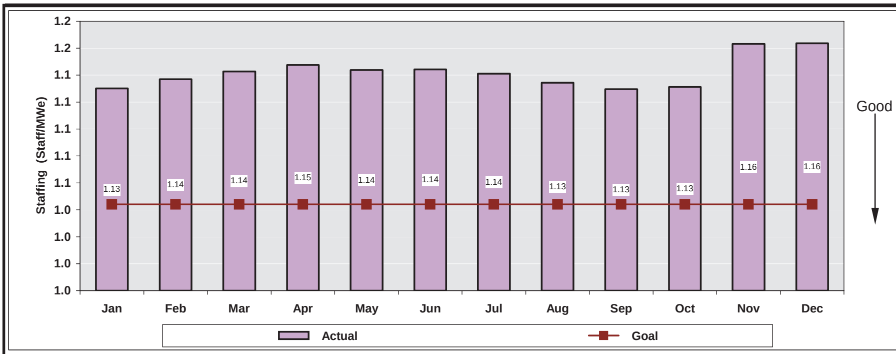


Data Elements

Production Cost (Cents/KWh)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
O&M Cost	0.38	0.46	0.53	0.58	0.53	0.51	0.54	0.55	0.61	0.60	0.61	0.66
Fuel Expense	0.28	0.32	0.35	0.34	0.33	0.34	0.34	0.34	0.34	0.34	0.35	0.36
Production Cost Goal	0.61	0.76	0.82	0.93	0.88	0.86	0.89	0.91	0.97	0.96	0.96	1.02
Production Cost Actual	0.65	0.78	0.88	0.92	0.86	0.84	0.88	0.89	0.95	0.95	0.96	1.02
Net Generation Year to Date (MWh)												
Actual	1,202,707	2,340,504	2,934,482	4,007,924	5,297,814	6,527,665	7,669,175	8,572,269	9,653,181	10,766,987	11,829,061	12,990,027
Goal	1,372,680	2,614,365	3,344,445	4,244,445	5,617,125	6,945,525	8,181,405	9,130,005	10,306,725	11,619,885	12,890,685	14,203,845

FIG. II–1. Production cost (c/kW·h).

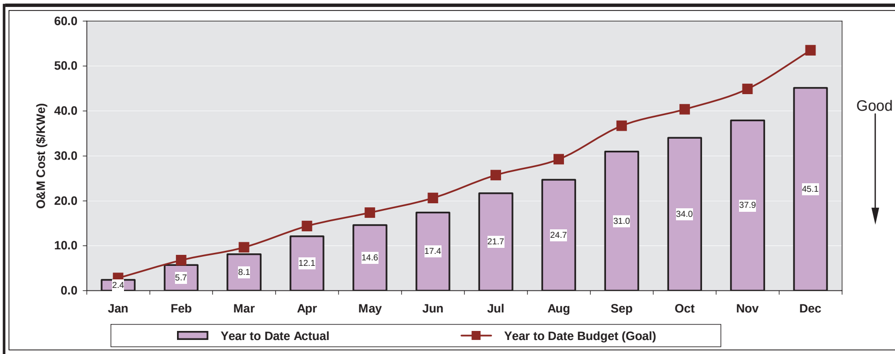
* Annex II remains unedited.



Data Elements

Staffing	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Staffing (Staff/MWe)												
Actual	1.13	1.14	1.14	1.15	1.14	1.14	1.14	1.13	1.13	1.13	1.16	1.16
Goal	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04
Installed Capacity (MWe)	1,906	1,906	1,906	1,906	1,906	1,906	1,906	1,906	1,906	1,906	1,906	1,906
Number of Nuclear staff (FTE's)												
Actual	2,154	2,167	2,178	2,187	2,180	2,181	2,175	2,162	2,153	2,156	2,217	2,218
Goal	1,990	1,990	1,990	1,990	1,990	1,990	1,990	1,990	1,990	1,990	1,990	1,990

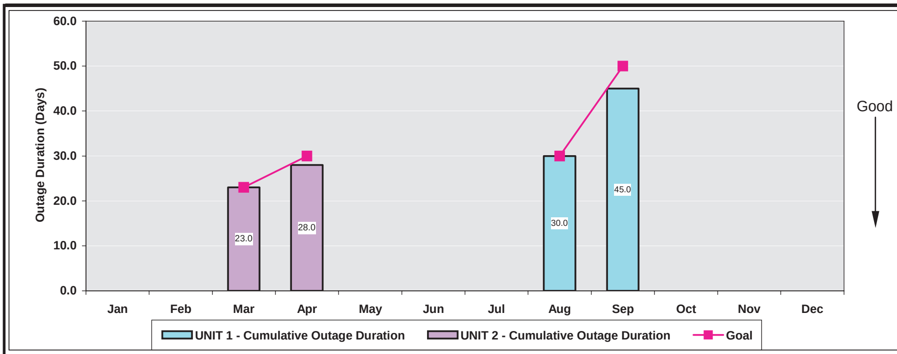
FIG. II–2. Staffing (staff/MW(e)).



Data Elements

O&M Cost	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
O&M Cost ($/KWe)												
Year to Date Actual	2.4	5.7	8.1	12.1	14.6	17.4	21.7	24.7	31.0	34.0	37.9	45.1
Year to Date Budget (Goal)	2.8	6.8	9.7	14.4	17.3	20.6	25.7	29.3	36.7	40.4	44.9	53.5
Installed Capacity (MWe)	1,906	1,906	1,906	1,906	1,906	1,906	1,906	1,906	1,906	1,906	1,906	1,906
O&M Cost ($X1000)												
Monthly Actual	4,557	6,301	4,658	7,563	4,807	5,278	8,173	5,744	11,928	5,883	7,332	13,793
Monthly Budget	5,402	7,470	5,522	8,966	5,698	6,257	9,689	6,810	14,140	6,974	8,692	16,351
Net Design Electrical Capacity (Mwe)	1,906	1,906	1,906	1,906	1,906	1,906	1,906	1,906	1,906	1,906	1,906	1,906

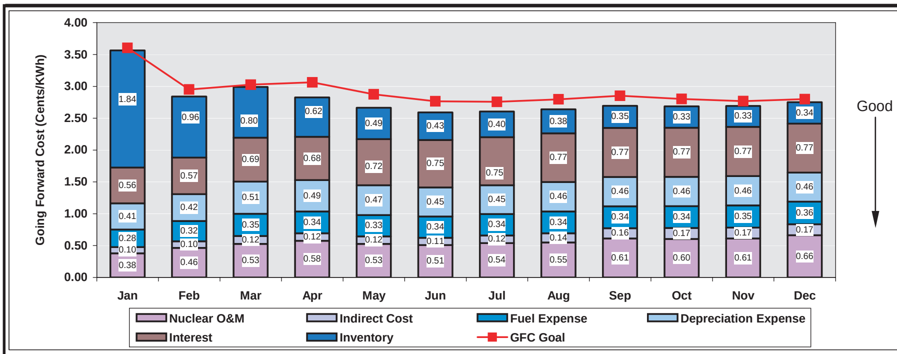
FIG. II–3. O&M cost ($/kW(e)).



Data Elements

Outage Duration (Days)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
UNIT 1 - Cumulative Outage Duration								30.0	45.0			
UNIT 2 - Cumulative Outage Duration			23.0	28.0								
Goal			23.0	30.0				30.0	50.0			

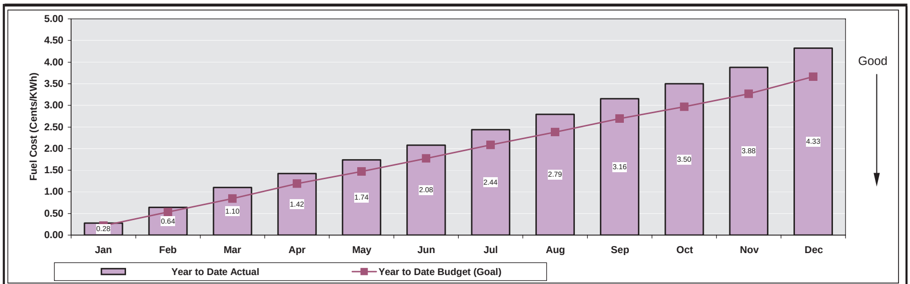
FIG. II–4. Refuelling/maintenance outage duration (d).



Data Elements

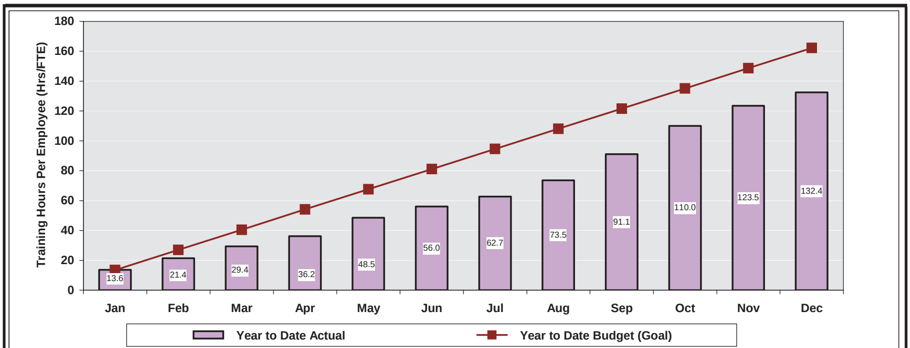
Going Forward Cost (Cents/KWh)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Total O&M Cost	0.38	0.46	0.53	0.58	0.53	0.51	0.54	0.55	0.61	0.60	0.61	0.66
Total Indirect Cost	0.10	0.10	0.12	0.12	0.12	0.11	0.12	0.14	0.16	0.17	0.17	0.17
Fuel Cost	0.28	0.32	0.35	0.34	0.33	0.34	0.34	0.34	0.34	0.34	0.35	0.36
Annual Depreciation Expense	0.41	0.42	0.51	0.49	0.47	0.45	0.45	0.46	0.46	0.46	0.46	0.46
Interest on Debt	0.56	0.57	0.69	0.68	0.72	0.75	0.75	0.77	0.77	0.77	0.77	0.77
Inventory Carrying Cost	1.84	0.96	0.80	0.62	0.49	0.43	0.40	0.38	0.35	0.33	0.33	0.34
Going Forward Cost Goal	3.61	2.95	3.03	3.06	2.87	2.77	2.76	2.80	2.85	2.80	2.77	2.80
Going Forward Cost Actual	3.56	2.84	2.99	2.83	2.67	2.59	2.60	2.64	2.70	2.69	2.69	2.75

FIG. II–5. Going forward cost (c/kW·h).



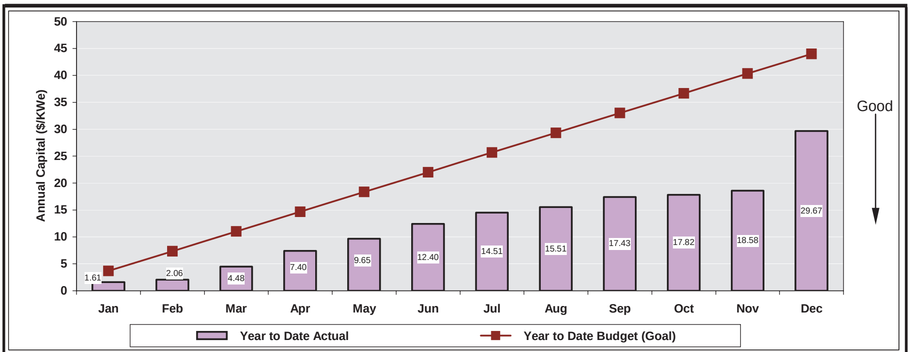
Data Elements												
Fuel Cost (Cents/KWh)	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
Year to Date Actual	0.28	0.64	1.10	1.42	1.74	2.08	2.44	2.79	3.16	3.50	3.88	4.33
Year to Date Budget (Goal)	0.22	0.53	0.85	1.19	1.47	1.77	2.09	2.38	2.70	2.97	3.27	3.66
Fuel Expense ($X1000)												
Year to Date Actual	3,314	7,472	10,211	13,663	17,730	21,914	26,005	29,196	33,132	36,965	40,987	46,187
Year to Date Goal	2,955	6,910	9,183	12,301	16,149	20,135	24,011	26,820	30,513	34,082	37,876	43,067
Net Generation (MWh)												
Year to Date Actual	1,202,707	2,340,504	2,934,482	4,007,924	5,297,814	6,527,665	7,669,175	8,572,269	9,653,181	10,766,987	11,829,061	12,990,027
Year to Date Goal	1,372,680	2,614,365	3,344,445	4,244,445	5,617,125	6,945,525	8,181,405	9,130,005	10,306,725	11,619,885	12,890,685	14,203,845

FIG. II–6. Training hours per employee (h/FTE).



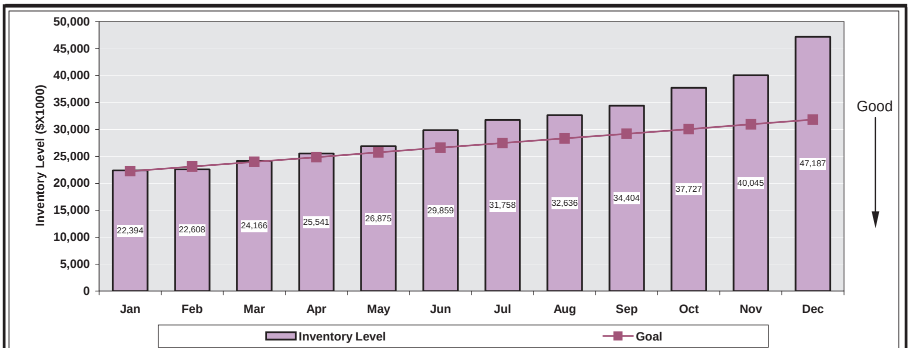
Data Elements												
Training Hours Per Employee	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
Year to Date Actual	13.6	21.4	29.4	36.2	48.5	56.0	62.7	73.5	91.1	110.0	123.5	132.4
Year to Date Budget (Goal)	13.5	27.0	40.5	54.1	67.6	81.1	94.6	108.1	121.6	135.1	148.6	162.2
Training Hours												
Year to Date Actual	17,082	26,784	36,909	45,446	60,775	70,203	78,587	92,221	114,261	137,959	154,869	166,049
Year to Date Budget	15,000	30,000	45,000	60,000	75,000	90,000	105,000	120,000	135,000	150,000	165,000	180,000
Number of Employees												
Actual	1,254	1,254	1,254	1,254	1,254	1,254	1,254	1,254	1,254	1,254	1,254	1,254
Budget	1,110	1,110	1,110	1,110	1,110	1,110	1,110	1,110	1,110	1,110	1,110	1,110

FIG. II–7. Fuel cost ($).



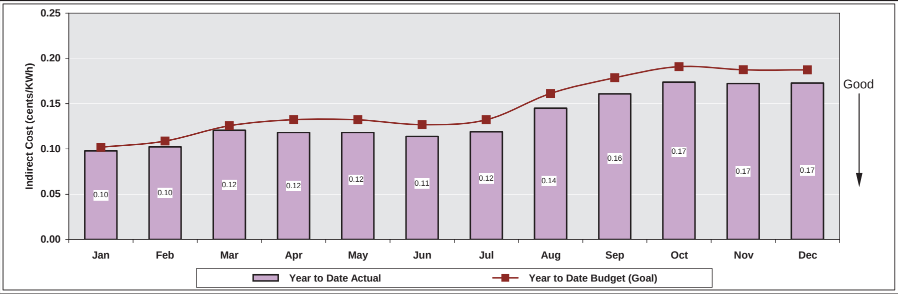
Data Elements												
Annual Capital Expenditures	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
Annual Capital ($/KWe)												
Year to Date Actual	1.61	2.06	4.48	7.40	9.65	12.40	14.51	15.51	17.43	17.82	18.58	29.67
Year to Date Budget (Goal)	3.67	7.33	11.00	14.67	18.34	22.00	25.67	29.34	33.01	36.67	40.34	44.01
Installed Capacity (MWe)	1,906	1,906	1,906	1,906	1,906	1,906	1,906	1,906	1,906	1,906	1,906	1,906
Annual capital ($X1000)												
Monthly Actual	3,064	857	4,624	5,557	4,297	5,238	4,012	1,915	3,652	747	1,442	21,141
Monthly Budget	6,990	6,990	6,990	6,990	6,990	6,990	6,990	6,990	6,990	6,990	6,990	6,990

FIG. II–8. Annual capital expenditure ($/kW(e)).



Data Elements												
Inventory Level ($X1000)	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
Inventory Level	22,394	22,608	24,166	25,541	26,875	29,859	31,758	32,636	34,404	37,727	40,045	47,187
Goal	22,253	23,122	23,992	24,861	25,730	26,599	27,469	28,338	29,207	30,076	30,946	31,815

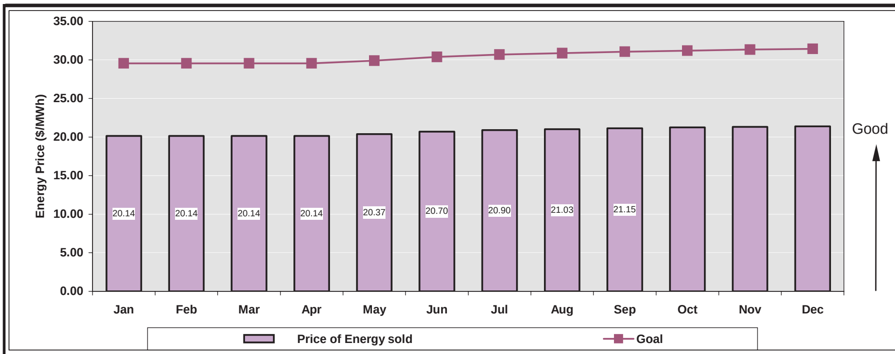
FIG. II–9. Inventory level ($).



Data Elements

Indirect Cost	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Indirect Cost (Cents/KWh)												
Year to Date Actual	0.10	0.10	0.12	0.12	0.12	0.11	0.12	0.14	0.16	0.17	0.17	0.17
Year to Date Budget (Goal)	0.10	0.11	0.13	0.13	0.13	0.13	0.13	0.16	0.18	0.19	0.19	0.19
Indirect Cost ($X1000)												
Monthly Actual	1,178	1,218	1,146	1,196	1,520	1,176	1,687	3,302	3,103	3,190	1,664	2,056
Year to Date Actual	1,178	2,396	3,542	4,738	6,258	7,434	9,121	12,423	15,526	18,716	20,380	22,436
Net Generation (MWh)												
Monthly Actual	1,202,707	1,137,797	593,978	1,073,442	1,289,890	1,229,851	1,141,510	903,094	1,080,912	1,113,806	1,062,074	1,160,966
Year to Date Plan (Goal)	1,372,680	2,614,365	3,344,445	4,244,445	5,617,125	6,945,525	8,181,405	9,130,005	10,306,725	11,619,885	12,890,685	14,203,845

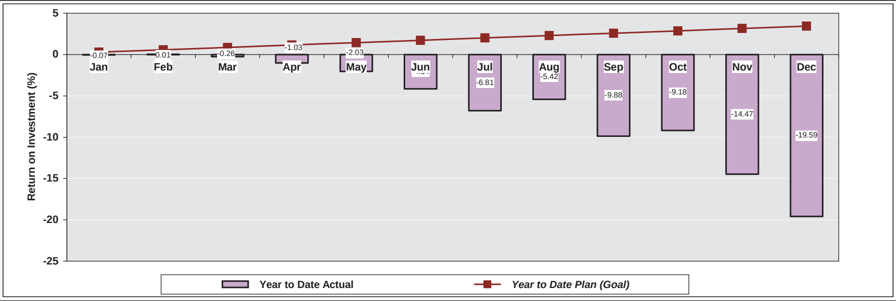
FIG. II–10. Indirect cost (c/kW·h).



Data Elements

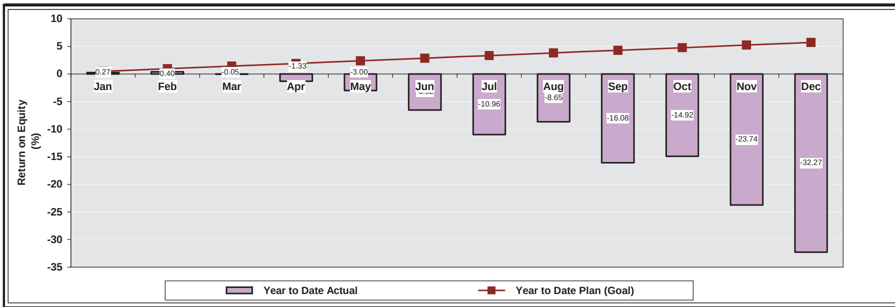
Energy Price ($/MWh)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Year to Date Weighted Average												
Price of Energy sold	20.14	20.14	20.14	20.14	20.37	20.70	20.90	21.03	21.15	21.25	21.32	21.39
Goal	29.55	29.55	29.55	29.55	29.91	30.39	30.69	30.87	31.05	31.21	31.33	31.43

FIG. II–11. Energy price ($/kW(e)).



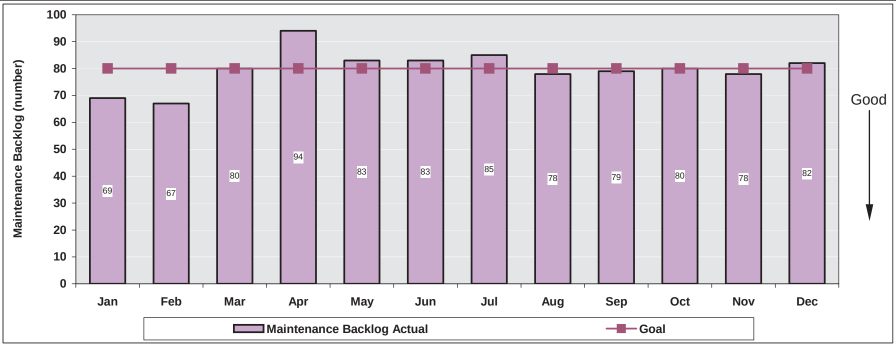
Data Elements												
Return on Investment (%)	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
Year to Date Actual	-0.07	0.01	-0.26	-1.03	-2.03	-4.14	-6.81	-5.42	-9.88	-9.18	-14.47	-19.59
Year to Date Plan (Goal)	0.29	0.57	0.86	1.15	1.43	1.72	2.01	2.29	2.58	2.86	3.15	3.43
Net Plant Investment												
Year to Date Actual	2,042,612	2,040,097	2,038,677	2,038,272	2,037,744	2,037,625	2,037,097	2,035,312	2,033,761	2,030,883	2,027,683	2,034,189
Year to Date Plan	2,044,116	2,044,961	2,045,946	2,046,999	2,048,089	2,049,196	2,050,309	2,051,424	2,052,529	2,053,642	2,054,752	2,055,880
Earnings												
Year to Date Actual	-1,390	188	-5,240	-20,904	-41,410	-84,398	-138,656	-110,356	-200,859	-186,478	-293,449	-398,543
Year to Date Plan	5,878	11,756	17,634	23,512	29,390	35,268	41,146	47,024	52,902	58,780	64,658	70,536

FIG. II–12. Return on investment (%).



Data Elements												
Return on Equity (%)	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
Year to Date Actual	0.27	0.40	-0.05	-1.33	-3.00	-6.52	-10.96	-8.65	-16.08	-14.92	-23.74	-32.27
Year to Date Plan (Goal)	0.48	0.96	1.44	1.91	2.39	2.87	3.34	3.82	4.30	4.77	5.24	5.72
Equity Investment ($X1000)												
Year to Date Actual	1,225,567	1,224,058	1,223,206	1,222,963	1,222,646	1,222,575	1,222,258	1,221,187	1,220,256	1,218,530	1,216,610	1,220,514
Year to Date Plan	1,226,470	1,226,977	1,227,567	1,228,200	1,228,853	1,229,517	1,230,186	1,230,854	1,231,518	1,232,185	1,232,851	1,233,528
Earnings ($X1000)												
Year to Date Actual	3,292	4,870	-558	-16,222	-36,728	-79,716	-133,974	-105,674	-196,177	-181,796	-288,767	-393,861
Year to Date Plan	5,878	11,756	17,634	23,512	29,390	35,268	41,146	47,024	52,902	58,780	64,658	70,536

FIG. II–13. Return on equity (%).



Data Elements

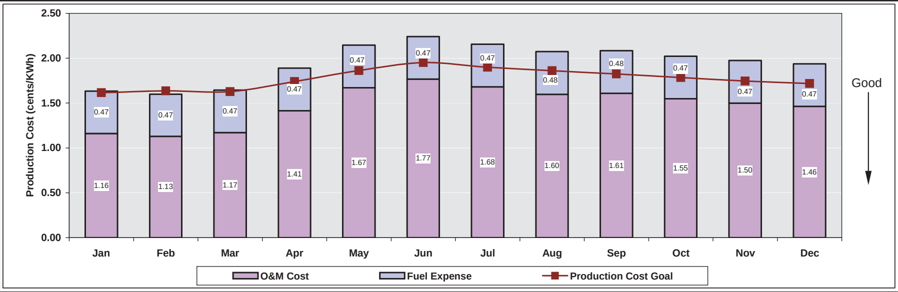
Maintenace Backlog (number)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Maintenance Backlog Actual	69	67	80	94	83	83	85	78	79	80	78	82
Goal	80	80	80	80	80	80	80	80	80	80	80	80

FIG. II–14. Maintenance backlog.

Annex III*

PERFORMANCE INDICATOR SPREADSHEETS

MONTHLY INDICATOR SPREADSHEETS



Data Elements

Production Cost (Cents/KWh)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
O&M Cost	1.16	1.13	1.17	1.41	1.67	1.77	1.68	1.60	1.61	1.55	1.50	1.46
Fuel Expense	0.47	0.47	0.47	0.47	0.47	0.47	0.47	0.48	0.48	0.47	0.47	0.47
Production Cost Goal	1.61	1.64	1.63	1.74	1.86	1.95	1.90	1.86	1.82	1.78	1.75	1.72
Production Cost Actual	1.63	1.60	1.64	1.89	2.14	2.24	2.15	2.07	2.08	2.02	1.97	1.94
Net Generation Year to Date (MWh)												
Actual	836,513	1,618,543	2,434,368	3,225,296	4,041,121	4,832,049	5,647,874	6,438,099	7,229,027	8,044,852	8,835,7 80	9,651,605
Goal	839,500	1,679,000	2,518,500	3,358,000	4,197,500	5,037,000	5,876,500	6,716,000	7,555,500	8,395,000	9,234,500	10,074,000

Definition

Production Cost expressed in Cents/KWh, is defined as the sum of nuclear O&M cost plus nuclear fuel cost, for a given period, divided by the net generation produced for the same period.
Total O&M Cost (expressed in thousands of $) is the total, non-fuel direct operations and maintenance cost consistent with NEPIS Account 2000, but expressed in US$.
Fuel Cost (expressed in thousands of $) is the total cost associated with a load of fuel in the reactor, which is "burned up" in a given period. It is the cost consistent with NEPIS Account A1900, but expressed in US$.
Net Generation (expressed in MWh) is the electric energy produced during the time period as measured at the unit outlet terminals, i.e. after deducting the electric energy taken by the unit auxiliaries and the losses in transformers that are considered integral parts of the unit. It is the net generation consistent with NEPIS Account A1650 but expressed in US$.

Calculation:

$$\text{Production Cost (Cents/KWh)} = \frac{\text{Nuclear O\&M (\$X1000)+Fuel Cost (\$X1000)}}{\text{Net Generation (MWh)}} \text{X100}$$

Analysis/Action

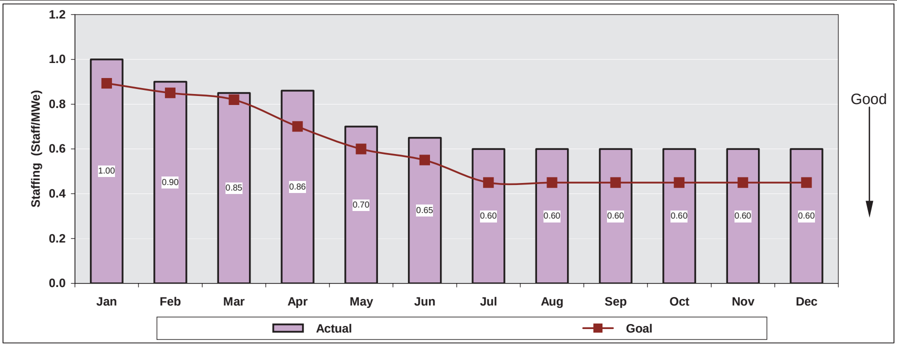
Goal

Comments

Data Source: | *Analysis by:* | *Company:*

FIG. III–1. Production cost (c/kW·h).

* Annex III remains unedited.



Data Elements

Staffing	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Staffing (Staff/MWe)												
Actual	1.00	0.90	0.85	0.86	0.70	0.65	0.60	0.60	0.60	0.60	0.60	0.60
Goal	0.89	0.85	0.82	0.70	0.60	0.55	0.45	0.45	0.45	0.45	0.45	0.45
Installed Capacity (MWe)	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000
Number of Nuclear staff (FTE's)												
Actual	1,000	900	850	860	700	650	600	600	600	600	600	600
Goal	893	850	820	700	600	550	450	450	450	450	450	450

Definition

Staffing Level expressed as Staff/Mwe, is defined as the ratio of the number of permanent nuclear staff, at a given point in time, divided by the design electrical capacity of the plant or unit.
Permanent Nuclear Staff, expressed in FTE's, includes on-site (located at the nuclear facility) and off-site (located at headquarters etc.) utility employees and long-term contracted labor for the nuclear facility. Permanent nuclear staff excludes short-term contractors and services.
Long Term Contractors expressed in FTE's, are non-utility (contracted) employees in staff augmentation positions of duration greater than six months.
Design Electrical Capacity Net, expressed in MWe, is the net generating capacity of the unit or plant consistent with NEPIS Account A1645 but expressed in US$.

Calculation:

$$\text{Staffing Level (Staff/MWe)} = \frac{\text{Permanent Nuclear Staff (FTE's)}}{\text{Net Design Electrical Capacity (MWe)}}$$

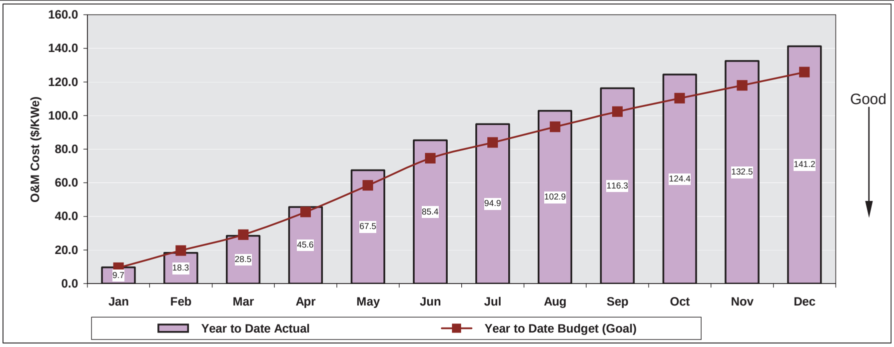
Analysis/Action

Goal

Comments

Data Source:	***Analysis by:***	***Company:***

FIG. III–2. Staffing.



Data Elements

O&M Cost	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
O&M Cost ($/KWe)												
Year to Date Actual	9.7	18.3	28.5	45.6	67.5	85.4	94.9	102.9	116.3	124.4	132.5	141.2
Year to Date Budget (Goal)	9.5	19.6	29.1	42.6	58.4	74.6	83.9	93.3	102.3	110.3	117.9	125.8
Installed Capacity (MWe)	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000
O&M Cost ($X1000)												
Monthly Actual	9,715	8,554	10,234	17,114	21,890	17,843	9,554	7,952	13,404	8,177	8,076	8,653
Monthly Budget	9,500	10,120	9,500	13,500	15,800	16,200	9,300	9,400	9,000	8,000	7,600	7,900
Net Design Electrical Capacity (Mwe)	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000

Definition

Nuclear O&M Cost (O&M), expressed in $/KWe, is defined as the total operations & maintenance (O&M) cost for a given period divided by the net design electrical capacity of the unit or plant.
Total O&M Cost, expressed in $X1000, are the total, direct, non-fuel, annual reoccurring labor and material costs including operations, maintenance, engineering support services and plant administration. It is the cost consistent with NEPIS Account 2000, but expressed in US$.
Design Electrical Capacity Net, expressed in MWe, is the net generating capacity of the unit or plant consistent with NEPIS Account A1645.

Calculation:

$$\text{O\&M (\$/KWe)} = \frac{\text{Total O\&M Cost \$X1000)}}{\text{Net Design Electrical Capacity (MWe)}}$$

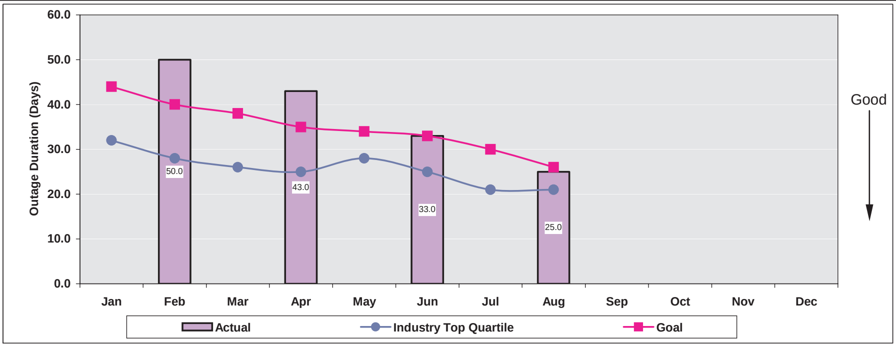
Analysis/Action

Goal

Comments

Data Source: ***Analysis by:*** ***Company:***

FIG. III–3. O&M cost ($/kW(e)).



Data Elements

Outage Duration (Days)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Actual		50.0		43.0		33.0		25.0				
Goal	44.0	40.0	38.0	35.0	34.0	33.0	30.0	26.0				
Industry Top Quartile	32.0	28.0	26.0	25.0	28.0	25.0	21.0	21.0				

Definition

Refueling/Maintenance Outage Duration, expressed in days, is defined as the number of days, breaker to breaker, since the reactor was shut down to perform the most recently completed refueling outage or major maintenance outage.
Refueling/Maintenance Outage Duration is consistent with NEPIS Accounts A1715 and A1690 for the most recently completed refueling outage or maintenance outage.
Major Maintenance Outage, expressed in days, is a non-refueling outage of greater than 20 days duration

Analysis/Action

Goal

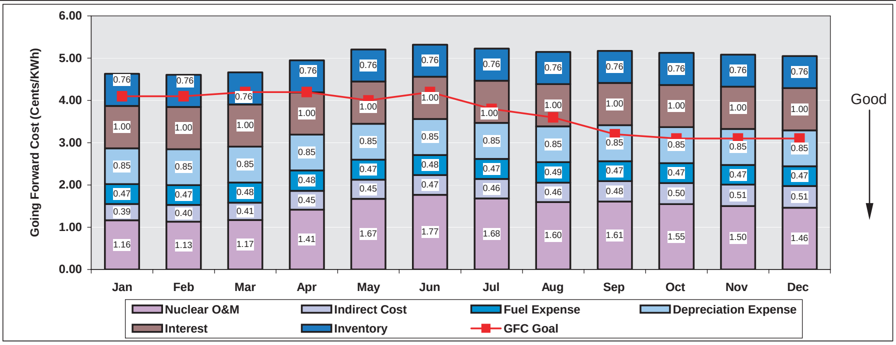
Comments

Data Source:

Analysis by:

Company:

FIG. III–4. Refuelling/maintenance outage duration (d).



Data Elements

Going Forward Cost (Cents/KWh)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Total O&M Cost	1.16	1.13	1.17	1.41	1.67	1.77	1.68	1.60	1.61	1.55	1.50	1.46
Total Indirect Cost	0.39	0.40	0.41	0.45	0.45	0.47	0.46	0.46	0.48	0.50	0.51	0.51
Fuel Cost	0.47	0.47	0.48	0.48	0.47	0.48	0.47	0.49	0.47	0.47	0.47	0.47
Annual Depreciation Expense	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85
Interest on Debt	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Inventory Carrying Cost	0.76	0.76	0.76	0.76	0.76	0.76	0.76	0.76	0.76	0.76	0.76	0.76
Going Forward Cost Goal	4.10	4.10	4.20	4.20	4.00	4.20	3.80	3.60	3.20	3.10	3.10	3.10
Going Forward Cost Actual	4.60	4.62	4.61	4.74	4.86	4.96	4.90	4.86	4.82	4.79	4.77	4.76

Definition

Going Forward Cost (GFC), expressed in Cents/KWh, is defined as the sum of Nuclear O&M Cost plus Indirect Cost plus Fuel Cost plus the carrying cost on "Going Forward" net outstanding capital additions and Inventory for a given period divided by the net generation produced for the same period.

Going Forward Net Outstanding Capital (GFNOC) is defined as the total investment in capital additions less the total depreciation of capital additions from a specified point in time through the period of the calculation.

Cost of GFNOC is defined as the weighted average cost of the Going Forward Net Outstanding Capital.

Total Direct O&M Cost, expressed in $X1000, is the total, non-fuel direct operations and maintenance cost consistent with NEPIS Account 2000 but expressed in US$.

Total Indirect Cost, expressed in $X1000, refers to corporate, non-fuel O&M expenses, including labor and materials, relating to a specific nuclear generating facility (plant or unit), not directly associated with the “on site” operations and maintenance of the plant or unit including liability, property& replacement power insurance, costs for pensions, medical benefits & payroll taxes and corporate administrative and general expenses which would be allocated to nuclear such as legal, human resources executive functions, accounting, etc. It is the cost consistent with NEPIS Account 2500, but expressed in US$.

Total Fuel Cost, expressed in $X1000, is the total cost associated with a load of fuel in the reactor which is "burned up" in a given period. It is the cost consistent with NEPIS Account A1900, but expressed in US$.

Inventory Carrying Cost is defined as the average outstanding inventory value (millions of $) for the period of the calculation. The average outstanding inventory value is the sum of the inventory value at the beginning of the period plus the inventory value at the end of the period divided by 2 and multiplied by the weighted average cost of Capital Rate.

Annual Depreciation Expense is the annual allowance for the depreciation of property representing that portion that has been “used up” during the previous twelve months.

Net Generation, expressed in MWh, is the electric energy produced during the time period as measured at the unit outlet terminals, i.e. after deducting the electric energy taken by the unit auxiliaries and the losses in transformers that are considered integral parts of the unit. It is the net generation consistent with NEPIS Account A1650.

Calculation:

Going Forward Cost (Cents/KWh) =

$$\frac{\text{O\&M+Fuel+Indirect Cost + Inventory Carrying Costs + GFNOC cost X100}}{\text{Net Generation (MWh)}}$$

Analysis/Action

Goal

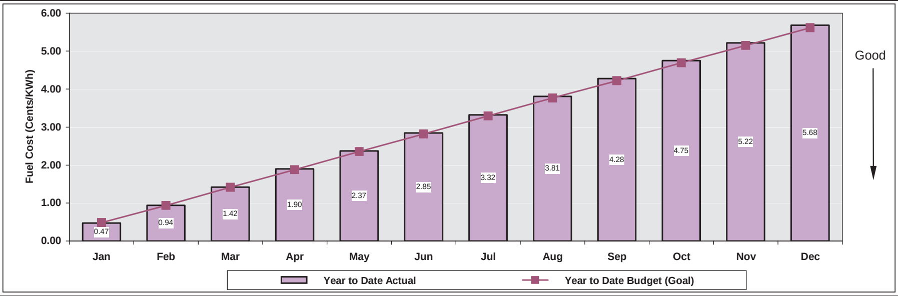
Comments

Data Source:

Analysis by:

Company:

FIG. III–5. Going forward cost (c/kW·h).



Data Elements

Nuclear Fuel Cost	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Fuel Cost (Cents/KWh)												
Year to Date Actual	0.47	0.94	1.42	1.90	2.37	2.85	3.32	3.81	4.28	4.75	5.22	5.68
Year to Date Budget (Goal)	0.48	0.93	1.41	1.88	2.36	2.82	3.29	3.77	4.22	4.69	5.15	5.62
Fuel Expense ($X1000)												
Monthly Actual	3,933	3,669	3,904	3,792	3,870	3,758	3,870	3,844	3,726	3,838	3,697	3809.00
Year to Date Actual	3,933	7,602	11,506	15,298	19,168	22,926	26,796	30,640	34,366	38,204	41,901	45710.00
Net Generation (MWh)												
Monthly Actual	836,513	782,030	815,825	790,928	815,825	790,928	815,825	790,225	790,928	815,825	790,928	815,825
Year to Date Actual	836,513	1,618,543	2,434,368	3,225,296	4,041,121	4,832,049	5,647,874	6,438,099	7,229,027	8,044,852	8,835,780	9,651,605

Definition

Fuel Cost is defined as the total annual expense associated with the "burn-up" of nuclear fuel resulting from the operation of the unit. This cost is based upon the amortized costs associated with the purchasing of uranium, conversion, enrichment and fabrication services along with storage and shipment costs and inventory (including interest) charges less any expected salvage value. Payments for fuel decommissioning and decontamination and current and prior spent nuclear fuel disposal costs including principle and interest are also included. Where applicable, costs associated with heavy water replenishment are also included. It is the cost consistent with NEPIS Account A1900, but expressed in US$.
Net Generation, expressed in MWh, is the electric energy produced during the time period as measured at the unit outlet terminals, i.e. after deducting the electric energy taken by the unit auxiliaries and the losses in transformers that are considered integral parts of the unit. It is the net generation consistent with NEPIS Account A1650.

Calculation:

$$\text{Fuel Cost (\$/MWh)} = \frac{\text{Fuel Cost (\$1000)}}{\text{Net Generation (MWh)}}$$

Analysis/Action

Goal

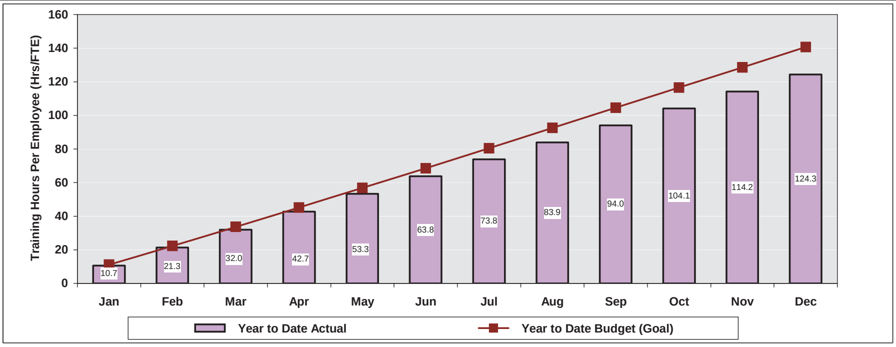
Comments

Data Source:

Analysis by:

Company:

FIG. III–6. Fuel cost (c/kW·h).



Data Elements

Training Hours Per Employee	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Year to Date Actual	10.7	21.3	32.0	42.7	53.3	63.8	73.8	83.9	94.0	104.1	114.2	124.3
Year to Date Budget (Goal)	11.1	22.3	33.7	45.2	56.8	68.6	80.5	92.5	104.5	116.6	128.6	140.6
Training Hours												
Year to Date Actual	4,800	9,600	14,400	19,200	24,000	28,800	33,600	38,400	43,200	48,000	52,800	57,600
Year to Date Budget	5,000	10,000	15,000	20,000	25,000	30,000	35,000	40,000	45,000	50,000	55,000	60,000
Number of Employees												
Actual	450	450	450	450	450	460	475	475	475	475	475	475
Budget	450	445	440	435	430	425	420	415	415	415	415	415

Definition

Training Hours per Employee (TH), expressed in Hours/FTE, is defined as the total number of training hours expended for a given period divided by the average number of full time nuclear employees for the same period.
Training Hours, expressed in Number of Hours, is the total number of man-hours expended by training department staff, including overtime, for a given period. It is the number of training department man-hours, which are consistent with the labor cost (contractor and utility employee) included in NEPIS Account 1220.
Full Time Nuclear Employees (FTE), expressed in Full Time Equivalent (FTE's), is the total number of full time nuclear staff, on site and off site, utility employees and long- term (greater than six months) contractor employees.

Calculation:
Training Hours per Employee (Hours/FTE) =

$$\frac{\text{Training Hours (Number of Hours)}}{\text{Full Time Nuclear Employees (FTE's)}}$$

Analysis/Action

Goal

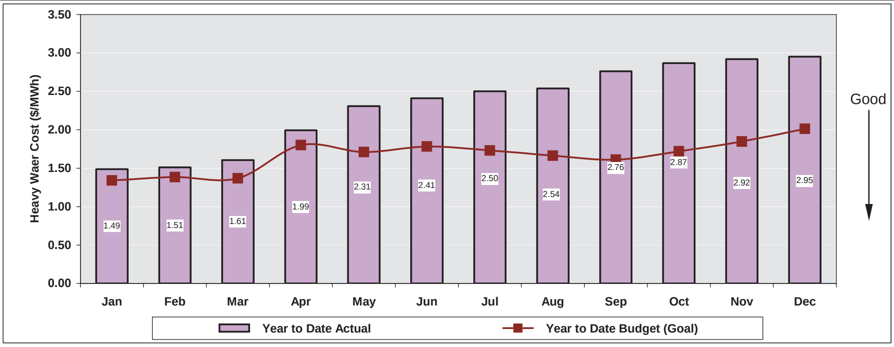
Comments

Data Source:

Analysis by:

Company:

FIG. III–7. Training hours per employee (h/FTE).



Data Elements

Heavy Water cost	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Heavy Water Cost ($/MWh)												
Year to Date Actual	1.49	1.51	1.61	1.99	2.31	2.41	2.50	2.54	2.76	2.87	2.92	2.95
Year to Date Budget (Goal)	1.34	1.38	1.37	1.80	1.71	1.78	1.73	1.66	1.61	1.72	1.85	2.01
Heavy Water Cost Cost ($X1000)												
Monthly Actual	1,245	1,200	1,467	2,521	2,895	2,321	2,477	2,211	3,629	3,111	2,722	2,698
Year to Date Actual	1,245	2,445	3,912	6,433	9,328	11,649	14,126	16,337	19,966	23,077	25,799	28,497
Net Generation (MWh)												
Monthly Actual	836,513	782,030	815,825	790,928	815,825	790,928	815,825	790,225	790,928	815,825	790,928	815,825

Definition

Heavy Water Cost (HWC), expressed in $/MWh, is defined as the annual heavy water cost for a given period divided by the net generation produced for the same period.

Annual Heavy Water Cost, expressed in $X1000, is the direct amortized annual cost of heavy water replenishment, including purchase, shipping and storage charges (only for PHWR's). It is consistent with the heavy water replenishment costs included in NEPIS Account A1901, but expressed in US$.

Net Generation, expressed in MWh, is the electric energy produced during the time period as measured at the unit outlet terminals, i.e. after deducting the electric energy taken by the unit auxiliaries and the losses in transformers that are considered integral parts of the unit. It is the net generation consistent with NEPIS Account A1650.

Calculation:

Heavy Water Cost ($/MWh) =

$$\frac{\text{Annual Heavy Water Cost (\$X1000)} \quad \text{X1000}}{\text{Net Generation (MWh)}}$$

Analysis/Action

Goal

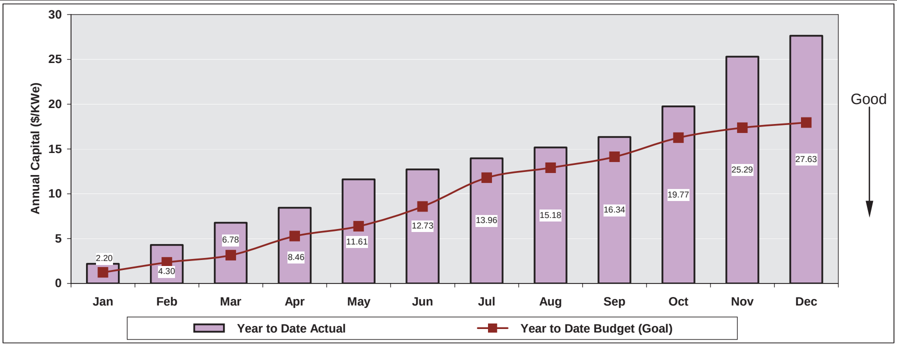
Comments

Data Source:

Analysis by:

Company:

FIG. III–8. Heavy water cost ($/MW·h).



Data Elements

Annual Capital Expenditures	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Annual Capital ($/KWe)												
Year to Date Actual	2.20	4.30	6.78	8.46	11.61	12.73	13.96	15.18	16.34	19.77	25.29	27.63
Year to Date Budget (Goal)	1.23	2.36	3.15	5.28	6.38	8.59	11.80	12.91	14.12	16.26	17.38	17.95
Installed Capacity (MWe)	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000
Annual capital ($X1000)												
Monthly Actual	2,200	2,100	2,478	1,677	3,150	1,120	1,234	1,221	1,156	3,434	5,521	2,334
Monthly Budget	1,234	1,124	789	2,134	1,098	2,211	3,211	1,111	1,212	2,131	1,123	569

Definition

Annual Capital (AC), expressed in $/KWe, is defined as the current annual capital investment for a given period divided by the net design electrical capacity of the unit or plant.

Current Annual Capital Investment, expressed in $X1000, is the total of all costs associated with improvements and modifications made during the reporting year. It is the additional capital investment during the current reporting period, excluding interest. These costs should include design, installation, removal and salvage that occur during the reporting period. Other miscellaneous investment/capital additions such as facilities, computer equipment, moveable equipment and vehicles should also be included. These costs should be fully burdened with indirect costs and exclude interest during construction. It is the cost consistent with NEPIS Account A1810, but expressed in US$.

Design Electrical Capacity Net, expressed in MWe, is the net generating capacity of the unit or plant consistent with NEPIS Account A1645.

Calculation:

Annual Capital ($/KWe) =

$$\frac{\text{Current Annual Capital Investment (\$X1000)}}{\text{Net Design Electrical Capacity (MWe)}}$$

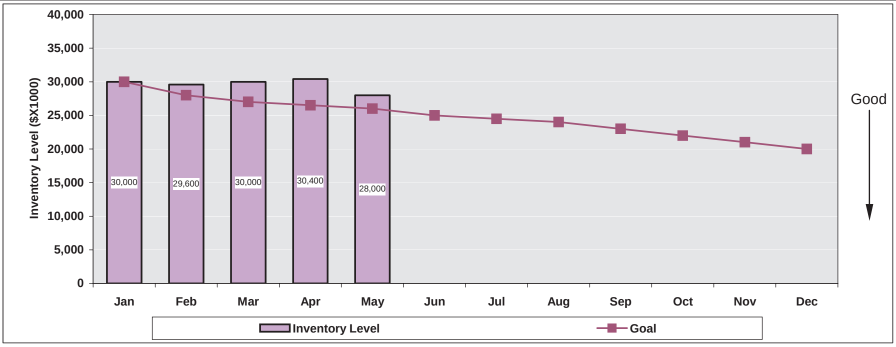
Analysis/Action

Goal

Comments

Data Source:	Analysis by:	Company:

FIG. III–9. Annual capital expenditure ($/kW(e)).



Data Elements

Inventory Level ($X1000)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Inventory Level	30,000	29,600	30,000	30,400	28,000							
Goal	30,000	28,000	27,000	26,500	26,000	25,000	24,500	24,000	23,000	22,000	21,000	20,000

Definition

Inventory Level (expressed in thousands of $) is the total value of the material and supplies inventory for a nuclear unit at a given point in time. It is consistent with NEPIS Account A1410. Please note that Fuel and Heavy water values are not included.

Analysis/Action

Goal

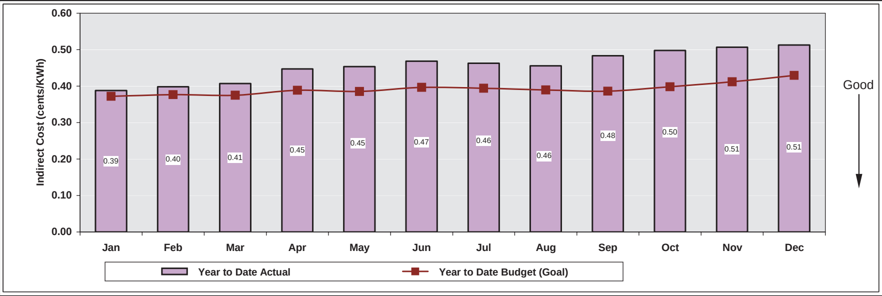
Comments

Data Source:

Analysis by:

Company:

FIG. III–10. Inventory level ($).



Data Elements

Indirect Cost	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Indirect Cost (Cents/KWh)												
Year to Date Actual	0.39	0.40	0.41	0.45	0.45	0.47	0.46	0.46	0.48	0.50	0.51	0.51
Year to Date Budget (Goal)	0.37	0.38	0.38	0.39	0.39	0.40	0.39	0.39	0.39	0.40	0.41	0.43
Indirect Cost ($X1000)												
Monthly Actual	3,245	3,200	3,467	4,521	3,895	4,321	3,477	3,211	5,629	5,111	4,722	4,698
Year to Date Actual	3,245	6,445	9,912	14,433	18,328	22,649	26,126	29,337	34,966	40,077	44,799	49,497
Net Generation (MWh)												
Monthly Actual	836,513	782,030	815,825	790,928	815,825	790,928	815,825	790,225	790,928	815,825	790,928	815,825
Year to Date Actual	836,513	1,618,543	2,434,368	3,225,296	4,041,121	4,832,049	5,647,874	6,438,099	7,229,027	8,044,852	8,835,780	9,651,605

Definition

Indirect Cost (IC), expressed in Cents/KWh, is defined as the total nuclear indirect cost for a given period divided by the net generation produced for the same period. Total Indirect Cost, expressed in $X1000, refers to corporate, non-fuel O&M expenses, including labor and materials, relating to a specific nuclear generating facility (plant or unit), not directly associated with the "on site" operations and maintenance of the plant or unit including liability, property& replacement power insurance, costs for pensions, medical benefits & payroll taxes and corporate administrative and general expenses which would be allocated to nuclear such as legal, human resources executive functions, accounting, etc. It is the cost consistent with NEPIS Account 2500, but expressed in US$.
Net Generation, expressed in MWh, is the electric energy produced during the time period as measured at the unit outlet terminals, i.e. after deducting the electric energy taken by the unit auxiliaries and the losses in transformers that are considered integral parts of the unit. It is the net generation consistent with NEPIS Account A1650.

Calculation:

$$\text{Indirect Cost (Cents/KWh)} = \frac{\text{Total Nuclear Indirect Cost (\$X1000)} \times 100}{\text{Net Generation (MWh)}}$$

Analysis/Action

Goal

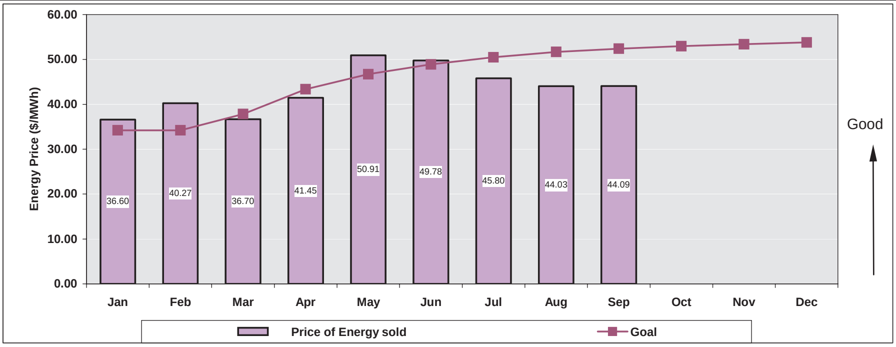
Comments

Data Source:

Analysis by:

Company:

FIG. III–11. Indirect cost (c/kW·h).



Data Elements

Energy Price ($/MWh)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Year to Date Weighted Average												
Price of Energy sold	36.60	40.27	36.70	41.45	50.91	49.78	45.80	44.03	44.09	0.00	0.00	0.00
Goal	34.23	34.23	37.82	43.37	46.69	48.91	50.49	51.68	52.38	52.95	53.41	53.79

Definition

Energy Price, expressed in $/MWh, is the generation weighted average price of the electricity sold for a given period.
Generation Weighted Average Price, expressed in $/MWh, is the equivalent price for all energy sold during the period.

Calculation:
Generation Weighted Average Price (GWAP) - Sample Calculation

Assume for a period: 1,000,000 MWh (G1) sold @ $30/MWh (P1)
1,500,000 MWh (G2) sold @ $35/MWh (P2)
2,000,000 MWh (G3) sold @ $50/MWh (P3)
Total Generation Sold (GT) = 4,500,000 MWh
Average (mean) Price = $38.33/MWh

$$GWAP = \frac{G1XP1 + G2XP2 + G3XP3}{GT} = \$40.55/MWh$$

Analysis/Action

Goal

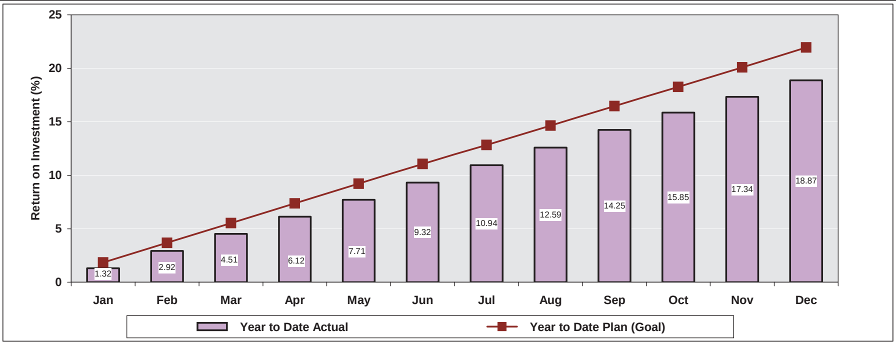
Comments

Data Source:

Analysis by:

Company:

FIG. III–12. *Energy price ($MW·h).*



Data Elements

Return on Investment (%)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Year to Date Actual	1.32	2.92	4.51	6.12	7.71	9.32	10.94	12.59	14.25	15.85	17.34	18.87
Year to Date Plan (Goal)	1.84	3.68	5.53	7.37	9.22	11.05	12.83	14.64	16.47	18.27	20.09	21.95
Net Plant Investment												
Year to Date Actual	250,017	249,991	250,134	249,961	250,365	250,044	249,417	248,631	247,732	247,916	249,685	250,653
Year to Date Plan	249,917	249,738	249,342	249,512	249,445	249,818	250,909	251,311	251,417	251,836	251,907	251,527
Earnings												
Year to Date Actual	3,292	7,292	11,292	15,292	19,292	23,292	27,292	31,292	35,292	39,292	43,292	47,292
Year to Date Plan	4,600	9,200	13,800	18,400	23,000	27,600	32,200	36,800	41,400	46,000	50,600	55,200
Interest on Debt												

Definition

Return on Investment (ROI), expressed as a %, is defined as the Profit or Earnings after taxes plus Interest paid for a given period divided by the Average Outstanding Investment for the same period.

Earnings, expressed as $X1000, are net earnings for common shareholders (Revenues less operating costs, taxes, depreciation and interest) for a given period.

Interest on Debt, expressed as thousand of $, is the return on average of long standing debt for a given period.

Average Outstanding Investment, expressed as $X1000, is the total investment value of the unit (less depreciation) at the beginning of the period plus the total investment value (less depreciation) of the unit at the end of the period divided by 2. It is consistent with NEPIS Accounts A1800, A1810 and A1820, but expressed in US $ converted at the exchange rate prevailing in the year of investment of the plant.

Calculation:

Return on Investment (%) =

$$\frac{\text{Total Return (Earnings+Interest)} \quad \text{X100}}{\text{Average Outstanding Investment (\$X1000)}}$$

Analysis/Action

Goal

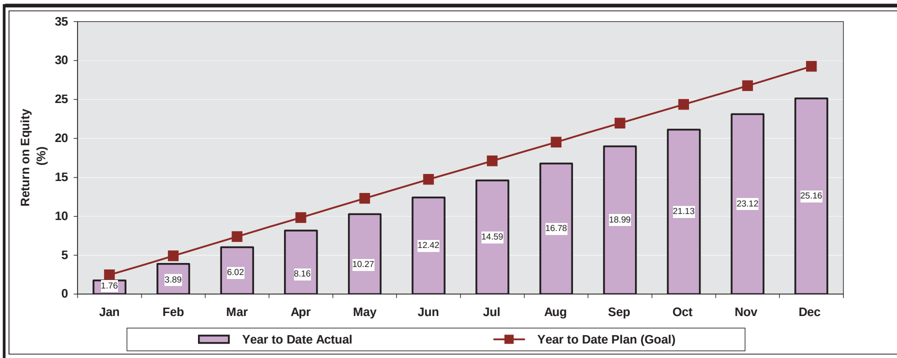
Comments

Data Source:

Analysis by:

Company:

FIG. III–13. *Return on investment (%).*



Data Elements

Return on Equity (%)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Year to Date Actual	1.76	3.89	6.02	8.16	10.27	12.42	14.59	16.78	18.99	21.13	23.12	25.16
Year to Date Plan (Goal)	2.45	4.91	7.38	9.83	12.29	14.73	17.11	19.52	21.96	24.35	26.78	29.26
Equity Investment ($X1000)												
Year to Date Actual	187,512	187,493	187,601	187,470	187,774	187,533	187,063	186,473	185,799	185,937	187,264	187,990
Year to Date Plan	187,438	187,303	187,007	187,134	187,084	187,363	188,182	188,483	188,563	188,877	188,930	188,645
Earnings ($X1000)												
Year to Date Actual	3,292	7,292	11,292	15,292	19,292	23,292	27,292	31,292	35,292	39,292	43,292	47,292
Year to Date Plan	4,600	9,200	13,800	18,400	23,000	27,600	32,200	36,800	41,400	46,000	50,600	55,200

Definition

Return on Equity (ROE), expressed as a %, is defined as the the Profit or Earnings after taxes for a given period divided by the average outstanding Equity Investment for the same period.
Earnings, expressed as $X1000, are net earnings for common shareholders (Revenues less operating costs, taxes, depreciation and interest).
Average Outstanding Equity Investment, expressed as $X1000, is the total equity investment value of the unit (less depreciation) at the beginning of the period plus the total equity investment value (less depreciation) of the unit at the end of the period divided by 2. It is consistent with NEPIS Accounts A1800, A1810 and A1820, but expressed in US $ converted at the exchange rate prevailing in the year of investment of the plant.

Calculation:

$$\text{Return on Equity (\%)} = \frac{\text{Earnings (\$X1000)} \quad \text{X100}}{\text{Average Outstanding Equity Investment (\$X1000)}}$$

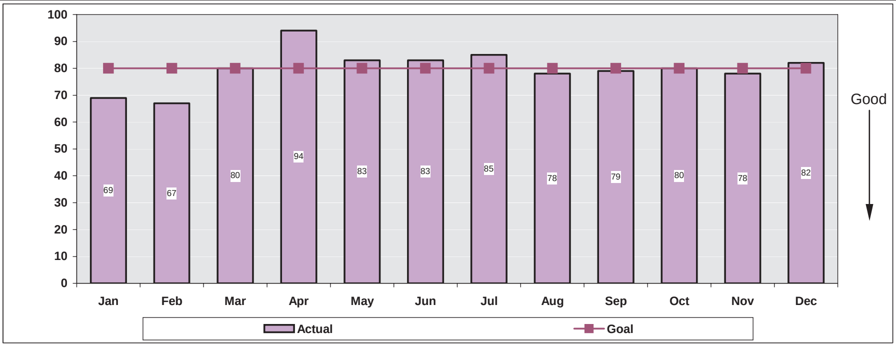
Analysis/Action

Goal

Comments

Data Source:	***Analysis by:***	***Company:***

FIG. III–14. Return on equity (%).



Data Elements

Maintenace Backlog (number)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Actual	69	67	80	94	83	83	85	78	79	80	78	82
Goal	80	80	80	80	80	80	80	80	80	80	80	80

Definition

Corrective Maintenance Backlog (number), is defined as the total number of corrective maintenance activities backlogged for a given period pendents of execution, expressed as number of work request.

Analysis/Action

Goal

Comments

Data Source:

Analysis by:

Company:

FIG. III–15. Maintenance backlog.

Annex IV*

PERFORMANCE INDICATOR DATA INPUT TABLES

TABLE IV–1. MONTHLY DATA INPUT TABLES

Going Forward Cost Go To Top

Data Year 8

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
O&M Cost ($X1000)												
Actual Monthly	9,715	8,554	13,234	17,114	21,890	17,843	9,554	7,952	13,404	8,177	8,076	8,653
Year to Date	9,715	18,269	29,503	45,617	67,507	85,350	94,904	102,856	116,260	124,437	132,513	141,166
Cents/KWh	1.16	1.13	1.17	1.41	1.67	1.77	1.68	1.60	1.61	1.55	1.50	1.46
Budget Monthly	9,500	10,120	9,500	13,500	15,800	16,200	9,300	9,400	9,000	8,000	7,600	7,900
Year to Date	9,500	19,620	29,120	42,620	58,420	74,620	83,920	93,320	102,320	110,320	117,920	125,820
Cents/KWh	1.13	1.17	1.16	1.27	1.39	1.46	1.43	1.39	1.36	1.31	1.28	1.25
Fuel Cost ($X1000)												
Actual Monthly	3,933	3,669	3,904	3,792	3,870	3,758	3,870	3,844	3,726	3,838	3,697	3,809
Year to Date	3,933	7,602	11,506	15,298	19,168	22,926	26,796	30,640	34,366	38,204	41,901	45,710
Cents/KWh	0.47	0.47	0.47	0.47	0.47	0.47	0.47	0.48	0.48	0.47	0.47	0.47
Budget Monthly	4,057	3,785	4,027	3,912	3,992	3,877	3,992	3,966	3,844	3,959	3,814	3,929
Year to Date	4,057	7,842	11,869	15,781	19,773	23,650	27,642	31,608	35,451	39,410	43,224	47,153
Cents/KWh	0.48	0.47	0.47	0.47	0.47	0.47	0.47	0.47	0.47	0.47	0.47	0.47
Indirect Cost ($X1000)												
Actual Monthly	3,245	3,200	3,467	4,521	3,895	4,321	3,477	3,211	5,629	5,111	4,722	4,698
Year to Date	3,245	6,445	9,912	14,433	18,328	22,649	26,126	29,337	34,966	40,077	44,799	49,497
Cents/KWh	0.39	0.40	0.41	0.45	0.45	0.47	0.46	0.46	0.48	0.50	0.51	0.51
Budget Monthly	3,125	3,200	3,125	3,600	3,125	3,000	3,200	3,000	3,000	4,261	4,632	5,211
Year to Date	3,125	6,325	9,450	13,050	16,175	19,075	23,175	26,175	29,175	33,436	38,068	43,279
Cents/KWh	0.37	0.38	0.38	0.39	0.39	0.40	0.39	0.39	0.39	0.40	0.41	0.43
Carrying Costs												
Annual Depreciation Expense	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85
Interest on Debt	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Inventory Carrying Cost	0.76	0.76	0.76	0.76	0.76	0.76	0.76	0.76	0.76	0.76	0.76	0.76
Net Generation (MWh)												
Actual Monthly	836,513	782,030	815,825	790,928	815,825	790,928	815,825	790,225	790,928	815,825	790,928	815,825
Year to Date	836,513	1,618,543	2,434,368	3,225,296	4,041,121	4,832,049	5,647,874	6,438,099	7,229,027	8,044,852	8,835,780	9,651,605
Plan Monthly	839,500	839,500	839,500	839,500	839,500	839,500	839,500	839,500	839,500	839,500	839,500	839,500
Year to Date	839,500	1,679,000	2,518,500	3,358,000	4,197,500	5,037,000	5,876,500	6,716,000	7,555,500	8,395,000	9,234,500	10,074,000
Going Forward Cost (Cents/KWh)												
Goal	4.10	4.10	4.20	4.20	4.00	4.20	3.80	3.60	3.20	3.10	3.10	3.10
Actual	4.63	4.62	4.61	4.74	4.86	4.96	4.90	4.86	4.82	4.79	4.77	4.76

Fuel Cost Go To Top

Data Year 8

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Nuclear Fuel Cost (Cents/KWh)												
Actual Monthly	0.47	0.47	0.48	0.48	0.47	0.48	0.47	0.49	0.47	0.47	0.47	0.47
Year to Date	0.47	0.94	1.42	1.90	2.37	2.85	3.32	3.81	4.28	4.75	5.22	5.69
Budget Monthly	0.48	0.45	0.48	0.47	0.48	0.46	0.48	0.47	0.46	0.47	0.45	0.47
Year to Date	0.48	0.93	1.41	1.88	2.36	2.82	3.29	3.77	4.22	4.69	5.15	5.62
Nuclear Fuel Expense ($X1000)												
Actual Monthly	3,933	3,669	3,904	3,792	3,870	3,758	3,870	3,844	3,726	3,838	3,697	3,809
Year to Date	3,933	7,602	11,506	15,298	19,168	22,926	26,796	30,640	34,366	38,204	41,901	45,710
Budget Monthly	4,057	3,785	4,027	3,912	3,992	3,877	3,992	3,966	3,844	3,959	3,814	3,929
Year to Date	4,057	7,842	11,869	15,781	19,773	23,650	27,642	31,608	35,451	39,410	43,224	47,153
Net Generation (MWh)												
Actual Monthly	836,513	782,030	815,825	790,928	815,825	790,928	815,825	790,225	790,928	815,825	790,928	815,825
Year to Date	836,513	1,618,543	2,434,368	3,225,296	4,041,121	4,832,049	5,647,874	6,438,099	7,229,027	8,044,852	8,835,780	9,651,605
Plan Monthly	839,500	839,500	839,500	839,500	839,500	839,500	839,500	839,500	839,500	839,500	839,500	839,500
Year to Date	839,500	1,679,000	2,518,500	3,358,000	4,197,500	5,037,000	5,876,500	6,716,000	7,555,500	8,395,000	9,234,500	10,074,000

Training Hrs per Employee Go To Top

Data Year 8

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Training Hours (Hours)												
Actual Monthly	4,800	4,800	4,800	4,800	4,800	4,800	4,800	4,800	4,800	4,800	4,800	4,800
Year to Date	4,800	9,600	14,400	19,200	24,000	28,800	33,600	38,400	43,200	48,000	52,800	57,600
Budget Monthly	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000
Year to Date	5,000	10,000	15,000	20,000	25,000	30,000	35,000	40,000	45,000	50,000	55,000	60,000
Number of Employees (FTE's)												
Actual	450	450	450	450	450	450	475	475	475	475	475	475
Budget	450	445	440	435	430	425	420	415	415	415	415	415
Training Hrs/Employee (Number)												
Actual Year to Date	10.7	21.3	32.0	42.7	53.3	63.8	73.8	83.8	94.0	104.1	114.2	124.3
Budget Year to Date	11.1	22.3	33.7	45.2	56.8	68.6	80.5	92.5	104.5	116.8	128.8	140.8

* Annex IV remains unedited.

Production Cost

Go To: Staffing Level | Outage | Fuel Cost | [illegible] | [illegible] | Energy Price | [illegible]
O&M Cost | [illegible] | Training Hrs | Capital | [illegible] | [illegible] | Ranking

First Year
Unit Name

	0	1	2	3	4	5	6	7	8	9	10	11
Nuclear O&M ($X1000)												
Actual	141,666	125,000	124,000	128,000	121,300	122,000	122,700	123,400	124,100	124,800	125,500	126,200
Cents/KWh	1.47	1.39	1.41	1.33	1.25	1.25	1.26	1.29	1.29	1.30	1.31	1.31
Budget	125,820	110,000	122,000	114,700	120,500	109,766	123,090	112,346	121,111	114,321	126,800	108,671
Cents/KWh	1.26	1.09	1.21	1.14	1.20	1.09	1.22	1.12	1.20	1.13	1.26	1.08
Fuel Expense ($X1000)												
Actual	45,710	45,000	36,000	36,000	45,000	36,000	36,000	45,000	36,000	36,000	37,905	37,890
Cents/KWh	0.47	0.50	0.41	0.38	0.46	0.37	0.37	0.47	0.38	0.38	0.39	0.39
Budget	44,000	42,345	44,675	42,111	44,000	42,345	44,675	42,111	44,000	42,345	44,675	42,111
Cents/KWh	0.44	0.42	0.44	0.42	0.44	0.42	0.44	0.42	0.44	0.42	0.44	0.42
Net Generation (MWh)												
Actual	9,651,605	9,000,000	8,799,000	9,600,000	9,733,000	9,733,000	9,733,000	9,600,000	9,600,000	9,600,000	9,600,000	9,600,000
Goal	10,074,000	10,074,000	10,074,000	10,074,000	10,074,000	10,074,000	10,074,000	10,074,000	10,074,000	10,074,000	10,074,000	10,074,000
Production Cost (Cents/KWh)												
Actual	1.94	1.89	1.82	1.71	1.71	1.62	1.63	1.75	1.67	1.68	1.70	1.71
Goal	1.69	1.51	1.65	1.56	1.63	1.51	1.67	1.53	1.64	1.56	1.70	1.50

Staffing Level

Go To: Top

	0	1	2	3	4	5	6	7	8	9	10	11
Nuclear Unit Staff (FTE's)												
Group A	300	300	300	360	200	150	125	125	125	125	125	125
Group B	55	55	55	55	30	30	30	30	30	30	30	30
Group C	450	400	350	400	325	325	300	300	300	300	300	300
Group D	150	100	100	100	100	100	100	100	100	100	100	100
Group E	45	45	45	45	45	45	45	45	45	45	45	45
Total Unit Staff (FTE's)												
Actual	1,000	900	850	960	700	650	600	600	600	600	600	600
Goal	893	850	820	700	600	550	450	450	450	450	450	450
Installed Capacity (MWe)	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000
Staffing Level (Staff/MWe)												
Actual	1.00	0.90	0.85	0.96	0.70	0.65	0.60	0.60	0.60	0.60	0.60	0.60
Goal	0.89	0.85	0.82	0.70	0.60	0.55	0.45	0.45	0.45	0.45	0.45	0.45

O&M Cost

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	0	1	2	3	4	5	6	7	8	9	10	11
Nuclear O&M ($X1000)												
Actual	141,666	125,000	124,000	128,000	121,300	122,000	122,700	123,400	124,100	124,800	125,500	126,200
Budget	125,820	110,000	122,000	114,700	120,500	109,766	123,090	112,346	121,111	114,321	126,800	108,671
Installed capacity (MWe)	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000
Nuclear O&M ($/KWe)												
Actual	141.7	125.0	124.0	128.0	121.3	122.0	122.7	123.4	124.1	124.8	125.5	126.2
Budget	125.8	110.0	122.0	114.7	120.5	109.8	123.1	112.3	121.1	114.3	126.8	108.7

Outage Duration

Go To: Top

	0	1	2	3	4	5	6	7	8	9	10	11
Outage Duration (Days)												
Actual		50		43		33		25				
Plan (Goal)	44	40	38	35	34	33	30	26				
Industry Quartile 1	32	28	26	25	28	26	21	21				
Quartile 2 (Median)												
Quartile 3												
Average												

Heavy Water Cost

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Data Year 0

		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Heavy Water Cost ($X1000)													
Actual	Monthly	1,245	1,200	1,467	2,521	2,895	2,321	2,477	2,211	3,629	3,111	2,722	2,698
	Year to Date	1,245	2,445	3,912	6,433	9,328	11,649	14,126	16,337	19,966	23,077	25,799	28,497
	$/MWh	1.49	1.51	1.61	1.99	2.31	2.41	2.50	2.54	2.76	2.87	2.92	2.95
Budget	Monthly	1,125	1,200	1,125	2,600	1,125	1,800	1,200	1,000	1,000	2,261	2,632	3,211
	Year to Date	1,125	2,325	3,450	6,050	7,175	8,975	10,175	11,175	12,175	14,436	17,068	20,279
	$/MWh	1.34	1.38	1.37	1.80	1.71	1.78	1.73	1.66	1.61	1.72	1.85	2.01
Net Generation (MWh)													
Actual	Monthly	836,513	782,030	815,825	790,928	815,825	790,928	815,825	790,225	790,928	815,825	790,928	815,825
	Year to Date	836,513	1,618,543	2,434,368	3,225,296	4,041,121	4,832,049	5,647,874	6,438,099	7,229,027	8,044,852	8,835,780	9,651,605
Plan	Monthly	839,500	839,500	839,500	839,500	839,500	839,500	839,500	839,500	839,500	839,500	839,500	839,500
	Year to Date	839,500	1,679,000	2,518,500	3,358,000	4,197,500	5,037,000	5,876,500	6,716,000	7,555,500	8,395,000	9,234,500	10,074,000

Annual Capital

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Data Year 0

		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Annual Capital ($X1000)													
Actual	Monthly	2,200	2,100	2,479	1,677	3,150	1,120	1,234	1,221	1,156	3,434	5,521	2,334
	Year to Date	2,200	4,300	6,779	8,456	11,605	12,725	13,959	15,180	16,336	19,770	25,291	27,625
Budget	Monthly	1,234	1,124	789	2,134	1,098	2,211	3,211	1,111	1,212	2,131	1,123	569
	Year to Date	1,234	2,358	3,147	5,281	6,379	8,590	11,801	12,912	14,124	16,255	17,378	17,947
Installed Capacity (MWe)		1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000
Annual Capital ($/KWe)													
Actual	Year to Date	2.2	4.3	6.8	8.5	11.6	12.7	14.0	15.2	16.3	19.8	25.3	27.6
Budget	Year to Date	1.2	2.4	3.1	5.3	6.4	8.6	11.8	12.9	14.1	16.3	17.4	17.9

Inventory Level

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Data Year 0

		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Inventory Level ($X1000)													
Actual	Monthly	30,000	29,600	30,000	30,400	28,000							
Goal	Monthly	30,000	28,000	27,000	26,500	26,000	25,000	24,500	24,000	23,000	22,000	21,000	20,000

Indirect Cost

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Data Year 0

		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Indirect Cost ($X1000)													
Actual	Monthly	3,245	3,200	3,467	4,521	3,895	4,321	3,477	3,211	5,629	5,111	4,722	4,698
	Year to Date	3,245	6,445	9,912	14,433	18,328	22,649	26,126	29,337	34,966	40,077	44,799	49,497
	Cents/KWh	0.39	0.40	0.41	0.45	0.45	0.47	0.46	0.46	0.48	0.50	0.51	0.51
Budget	Monthly	3,125	3,200	3,125	3,600	3,125	3,800	3,200	3,000	3,000	4,261	4,632	5,211
	Year to Date	3,125	6,325	9,450	13,050	16,175	19,975	23,175	26,175	29,175	33,436	38,068	43,279
	Cents/KWh	0.37	0.38	0.38	0.39	0.39	0.40	0.39	0.38	0.38	0.40	0.41	0.43
Net Generation (MWh)													
Actual	Monthly	836,513	782,030	815,825	790,928	815,825	790,928	815,825	790,225	790,928	815,825	790,928	815,825
	Year to Date	836,513	1,618,543	2,434,368	3,225,296	4,041,121	4,832,049	5,647,874	6,438,099	7,229,027	8,044,852	8,835,780	9,651,605
Plan	Monthly	839,500	839,500	839,500	839,500	839,500	839,500	839,500	839,500	839,500	839,500	839,500	839,500
	Year to Date	839,500	1,679,000	2,518,500	3,358,000	4,197,500	5,037,000	5,876,500	6,716,000	7,555,500	8,395,000	9,234,500	10,074,000

Energy Price

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Data Year 0

		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Energy Price ($/MWh)													
Actual Energy Sold													
	Monthly Weighted Average	36.60	44.20	29.60	56.10	88.30	44.00	22.20	31.40	44.60			
	Year to Date Weighted Average	36.60	40.27	36.75	41.45	50.91	49.75	46.80	44.03	44.09			
Goal													
	Monthly Weighted Average	34.23	34.23	46.00	60.00	60.00	60.00	60.00	60.00	58.00	58.00	58.00	58.00
	Year to Date Weighted Average	34.23	34.23	37.82	43.37	46.69	48.91	50.49	51.68	52.38	52.96	53.41	53.79
Net Generation (MWh)													
Actual	Monthly	836,513	782,030	815,825	790,928	815,825	790,928	815,825	790,225	790,928	815,825	790,928	815,825
	Year to Date	836,513	1,618,543	2,434,368	3,225,296	4,041,121	4,832,049	5,647,874	6,438,099	7,229,027	8,044,852	8,835,780	9,651,605
Plan	Monthly	839,500	839,500	839,500	839,500	839,500	839,500	839,500	839,500	839,500	839,500	839,500	839,500
	Year to Date	839,500	1,679,000	2,518,500	3,358,000	4,197,500	5,037,000	5,876,500	6,716,000	7,555,500	8,395,000	9,234,500	10,074,000

Return on Investment (ROI) Go To Year

Data Year 8

			Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Capital Additions		**($X1000)**												
Actual	Monthly		2,200	2,100	2,478	1,677	3,160	1,120	1,234	1,221	1,156	3,434	6,521	2,334
	Year to Date		2,200	4,300	6,778	8,455	11,605	12,725	13,959	15,180	16,336	19,770	25,291	27,625
Budget	Monthly		1,234	1,124	789	2,134	1,098	2,211	3,211	1,111	1,212	2,131	1,123	569
	Year to Date		1,234	2,358	3,147	5,281	6,379	8,590	11,801	12,912	14,124	16,255	17,378	17,947
Depreciation		**($X1000)**												
Actual	Monthly		2,167	2,167	2,167	2,167	2,167	2,167	2,167	2,167	2,167	2,167	2,167	2,167
	Year to Date		2,167	4,334	6,501	8,668	10,835	13,002	15,169	17,336	19,503	21,670	23,837	26,004
Plan	Monthly		1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400
	Year to Date		1,400	2,800	4,200	5,600	7,000	8,400	9,800	11,200	12,600	14,000	15,400	16,800
Net Plant Investment		**($X1000)**												
Prior			250,000											
Year to Date	Actual		250,017	249,991	250,134	249,961	250,365	250,044	249,417	248,631	247,732	247,916	249,605	250,653
	Plan		249,917	249,730	249,342	249,512	249,445	249,015	250,909	251,311	251,417	251,836	251,907	251,527
Earnings		**($X1000)**												
Actual	Monthly		4,000	4,000	4,000	4,000	4,000	4,000	4,000	4,000	4,000	4,000	4,000	4,000
	Year to Date		3,292	7,292	11,292	15,292	19,292	23,292	27,292	31,292	35,292	39,292	43,292	47,292
Plan	Monthly		4,600	4,600	4,600	4,600	4,600	4,000	4,000	4,000	4,600	4,600	4,600	4,600
	Year to Date		4,600	9,200	13,800	18,400	23,000	27,600	32,200	36,800	41,400	46,000	50,600	55,200
Return on Investment		**(%)**												
Actual			1.32	2.92	4.51	6.12	7.71	9.32	10.94	12.59	14.25	15.88	17.34	18.87
Plan			1.84	3.68	5.53	7.37	9.22	11.06	12.83	14.64	16.47	18.27	20.09	21.96

Return on Equity (ROE) Go To Year

Data Year 8

			Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Capital Additions		**($X1000)**												
Actual	Monthly		2,200	2,100	2,478	1,677	3,160	1,120	1,234	1,221	1,156	3,434	6,521	2,334
	Year to Date		2,200	4,300	6,778	8,455	11,605	12,725	13,959	15,180	16,336	19,770	25,291	27,625
Budget	Monthly		1,234	1,124	789	2,134	1,098	2,211	3,211	1,111	1,212	2,131	1,123	569
	Year to Date		1,234	2,358	3,147	5,281	6,379	8,590	11,801	12,912	14,124	16,255	17,378	17,947
Depreciation		**($X1000)**												
Actual	Monthly		2,167	2,167	2,167	2,167	2,167	2,167	2,167	2,167	2,167	2,167	2,167	2,167
	Year to Date		2,167	4,334	6,501	8,668	10,835	13,002	15,169	17,336	19,503	21,670	23,837	26,004
Plan	Monthly		1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400
	Year to Date		1,400	2,800	4,200	5,600	7,000	8,400	9,800	11,200	12,600	14,000	15,400	16,800
Net Plant Investment		**($X1000)**												
Prior			250,000											
Year to Date	Actual		250,017	249,991	250,134	249,961	250,365	250,044	249,417	248,631	247,732	247,916	249,605	250,653
	Plan		249,917	249,730	249,342	249,512	249,445	249,015	250,909	251,311	251,417	251,836	251,907	251,527
Debt Ratio		**(%)**	25	25	25	25	25	25	25	25	25	25	25	25
Equity Investment		**($X1000)**												
Year to Date	Actual		187,512	187,493	187,601	187,470	187,774	187,533	187,063	186,473	185,799	185,937	187,204	187,990
	Plan		187,438	187,303	187,007	187,134	187,084	187,363	188,182	188,483	188,563	188,877	188,930	188,645
Earnings		**($X1000)**												
Actual	Monthly		4,000	4,000	4,000	4,000	4,000	4,000	4,000	4,000	4,000	4,000	4,000	4,000
	Year to Date		3,292	7,292	11,292	15,292	19,292	23,292	27,292	31,292	35,292	39,292	43,292	47,292
Plan	Monthly		4,600	4,600	4,600	4,600	4,600	4,000	4,000	4,000	4,600	4,600	4,600	4,600
	Year to Date		4,600	9,200	13,800	18,400	23,000	27,600	32,200	36,800	41,400	46,000	50,600	55,200
Return on Equity		**(%)**												
Actual			1.76	3.89	6.02	8.16	10.27	12.42	14.59	16.78	18.99	21.13	23.12	25.16
Plan			2.45	4.91	7.36	9.83	12.29	14.73	17.11	19.52	21.96	24.36	26.79	29.26

Maintenance Backlog Go To Year

Data Year 8

		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Corrective Maintenance Backlog													
Actual	Monthly	89	87	80	94	80	80	86	78	79	80	78	82
Goal	Monthly	80	80	80	80	80	80	80	80	80	80	80	80

TABLE IV–2. YEARLY DATA INPUT TABLES

Production Cost — Go To: Staffing Level | Outage | Fuel Cost | Heavy Water | Inventory Level | Energy Price | [illegible] | O&M Cost | [illegible] | Training Hrs | Capital | Indirect Cost | [illegible] | Ranking

First Year
Unit Name

	0	1	2	3	4	5	6	7	8	9	10	11
Nuclear O&M ($X1000)												
Actual	141,666	125,000	124,000	128,000	121,300	122,000	122,700	123,400	124,100	124,800	125,500	126,200
Cents/KWh	1.47	1.39	1.41	1.33	1.25	1.25	1.26	1.29	1.29	1.30	1.31	1.31
Budget	125,820	110,000	122,000	114,700	120,500	109,760	123,090	112,346	121,111	114,321	126,800	108,671
Cents/KWh	1.25	1.09	1.21	1.14	1.20	1.09	1.22	1.12	1.20	1.13	1.26	1.08
Fuel Expense ($X1000)												
Actual	45,710	45,000	36,000	36,000	45,000	36,000	36,000	45,000	36,000	36,000	37,905	37,800
Cents/KWh	0.47	0.50	0.41	0.38	0.46	0.37	0.37	0.47	0.38	0.38	0.39	0.39
Budget	44,000	42,345	44,675	42,111	44,000	42,345	44,675	42,111	44,000	42,345	44,675	42,111
Cents/KWh	0.44	0.42	0.44	0.42	0.44	0.42	0.44	0.42	0.44	0.42	0.44	0.42
Net Generation (MWh)												
Actual	9,661,605	9,000,000	8,799,000	9,600,000	9,733,000	9,733,000	9,733,000	9,600,000	9,600,000	9,600,000	9,600,000	9,600,000
Goal	10,074,000	10,074,000	10,074,000	10,074,000	10,074,000	10,074,000	10,074,000	10,074,000	10,074,000	10,074,000	10,074,000	10,074,000
Production Cost (Cents/KWh)												
Actual	1.94	1.89	1.82	1.71	1.71	1.62	1.63	1.75	1.67	1.68	1.70	1.71
Goal	1.69	1.51	1.66	1.56	1.63	1.51	1.67	1.53	1.64	1.56	1.70	1.50

Staffing Level — Go To: Top

	0	1	2	3	4	5	6	7	8	9	10	11
Nuclear Unit Staff (FTE's)												
Group A	300	300	300	260	200	150	125	125	125	125	125	125
Group B	55	55	55	55	30	30	30	30	30	30	30	30
Group C	450	400	350	400	325	325	300	300	300	300	300	300
Group D	150	100	100	100	100	100	100	100	100	100	100	100
Group E	45	45	45	45	45	45	45	45	45	45	45	45
Total Unit Staff (FTE's)												
Actual	1,000	900	850	860	700	650	600	600	600	600	600	600
Goal	893	850	820	700	600	550	450	450	450	450	450	450
Installed Capacity (MWe)	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000
Staffing Level (Staff/MWe)												
Actual	1.00	0.90	0.85	0.86	0.70	0.65	0.60	0.60	0.60	0.60	0.60	0.60
Goal	0.89	0.85	0.82	0.70	0.60	0.55	0.45	0.45	0.45	0.45	0.45	0.45

O&M Cost — Go To: Top

	0	1	2	3	4	5	6	7	8	9	10	11
Nuclear O&M ($X1000)												
Actual	141,666	125,000	124,000	128,000	121,300	122,000	122,700	123,400	124,100	124,800	125,500	126,200
Budget	125,820	110,000	122,000	114,700	120,500	109,760	123,090	112,346	121,111	114,321	126,800	108,671
Installed capacity (MWe)	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000
Nuclear O&M ($/KWe)												
Actual	141.7	125.0	124.0	128.0	121.3	122.0	122.7	123.4	124.1	124.8	125.5	126.2
Budget	125.8	110.0	122.0	114.7	120.5	109.8	123.1	112.3	121.1	114.3	126.8	108.7

Outage Duration — Go To: Top

	0	1	2	3	4	5	6	7	8	9	10	11
Outage Duration (Days)												
Actual		50		43		33		25				
Plan (Goal)	44	40	38	35	34	33	30	28				
Industry Quartile 1	32	28	26	25	28	26	21	21				
Quartile 2 (Median)												
Quartile 3												
Average												

Going Forward Cost

Go To [Top]

	0	1	2	3	4	5	6	7	8	9	10	11
Nuclear O&M ($X1000)												
Actual	141,666	126,000	124,000	126,000	121,300	122,000	122,700	123,400	124,100	124,800	125,500	126,200
Cents/KWh	1.47	1.39	1.41	1.33	1.25	1.25	1.26	1.29	1.29	1.30	1.31	1.31
Budget	126,820	110,000	122,000	114,700	120,500	109,795	123,290	112,345	121,111	114,321	126,800	108,671
Cents/KWh	1.25	1.09	1.21	1.14	1.20	1.09	1.22	1.12	1.20	1.13	1.26	1.08
Fuel Expense ($X1000)												
Actual	45,710	45,000	36,000	36,000	45,000	36,000	36,000	45,000	36,000	36,000	37,905	37,890
Cents/KWh	0.47	0.50	0.41	0.38	0.46	0.37	0.37	0.47	0.38	0.38	0.39	0.39
Budget	44,000	42,346	44,675	42,111	44,000	42,346	44,675	42,111	44,000	42,346	44,675	42,111
Cents/KWh	0.44	0.42	0.44	0.42	0.44	0.42	0.44	0.42	0.44	0.42	0.44	0.42
Indirect Cost ($X1000)												
Actual	26,000	24,000	23,876	22,340	23,300	25,432	22,123	25,546	23,678	24,576	24,567	23,678
Cents/KWh	0.27	0.27	0.27	0.23	0.24	0.26	0.23	0.27	0.25	0.26	0.26	0.25
Budget	24,000	24,000	24,000	24,000	24,000	24,000	24,000	24,000	24,000	24,000	24,000	24,000
Cents/KWh	0.24	0.24	0.24	0.24	0.24	0.24	0.24	0.24	0.24	0.24	0.24	0.24
Carrying Cost												
Inventory Carrying Costs	0.76	0.76	0.76	0.76	0.76	0.76	0.76	0.76	0.76	0.76	0.76	0.76
Annual Depreciation Expense	0.86	0.86	0.86	0.86	0.86	0.86	0.86	0.86	0.86	0.86	0.86	0.86
Interest on Debt	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Net Generation (MWh)												
Actual	9,651,625	9,000,000	8,799,000	9,600,000	9,733,000	9,733,000	9,733,000	9,600,000	9,600,000	9,600,000	9,600,000	9,600,000
Goal	10,074,000	10,074,000	10,074,000	10,074,000	10,074,000	10,074,000	10,074,000	10,074,000	10,074,000	10,074,000	10,074,000	10,074,000
Going Forward Cost (Cents/KWh)												
Actual	4.62	4.77	4.70	4.55	4.56	4.49	4.47	4.63	4.52	4.54	4.57	4.57
Goal	4.53	4.36	4.50	4.40	4.40	4.30	4.51	4.30	4.49	4.40	4.55	4.34

Fuel Cost

Go To [Top]

	0	1	2	3	4	5	6	7	8	9	10	11
Nuclear Fuel Expense ($X1000)												
Actual	45,710	45,000	36,000	36,000	45,000	36,000	36,000	45,000	36,000	36,000	37,905	37,890
Budget	44,000	42,346	44,675	42,111	44,000	42,346	44,675	42,111	44,000	42,346	44,675	42,111
Net Generation (MWh)												
Actual	9,651,625	9,000,000	8,799,000	9,600,000	9,733,000	9,733,000	9,733,000	9,600,000	9,600,000	9,600,000	9,600,000	9,600,000
Goal	10,074,000	10,074,000	10,074,000	10,074,000	10,074,000	10,074,000	10,074,000	10,074,000	10,074,000	10,074,000	10,074,000	10,074,000
Nuclear Fuel Cost (Cents/KWh)												
Actual	0.47	0.50	0.41	0.38	0.46	0.37	0.37	0.47	0.38	0.38	0.39	0.39
Budget	0.44	0.42	0.44	0.42	0.44	0.42	0.44	0.42	0.44	0.42	0.44	0.42

Training Hrs per Employee

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	0	1	2	3	4	5	6	7	8	9	10	11
Training Hours (Hours)												
Actual	53,000	56,000	54,670	57,098	57,600	57,000	57,000	57,600	57,600	57,600	57,600	57,600
Budget	53,475	53,400	53,400	53,400	53,400	53,400	53,400	53,400	53,400	53,400	53,400	53,400
Number of Employees (FTE's)												
Actual	450	450	450	450	450	460	475	475	475	475	475	475
Budget	450	446	440	436	430	426	420	415	415	415	415	415
Training Hrs/Employee (Number)												
Actual	117.8	124.4	121.5	126.9	128.0	127.5	126.6	125.9	125.4	124.9	124.6	124.3
Budget	118.8	119.3	120.0	120.7	121.4	122.1	122.8	123.5	124.0	124.5	124.8	125.2

Heavy Water Cost

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	0	1	2	3	4	5	6	7	8	9	10	11
Heavy Water Cost ($X1000)												
Actual	24,555	23,587	21,346	23,444	22,222	23,456	26,789	26,789	26,789	26,789	26,789	26,789
$/MWh	2.54	2.62	2.43	2.44	2.28	2.41	2.75	2.79	2.79	2.79	2.79	2.79
Budget	25,000	25,000	25,000	25,000	24,988	23,456	23,000	23,000	23,000	23,000	23,000	23,000
$/MWh	2.48	2.48	2.48	2.48	2.48	2.33	2.28	2.28	2.28	2.28	2.28	2.28
Net Generation (MWh)												
Actual	9,651,625	9,000,000	8,799,000	9,600,000	9,733,000	9,733,000	9,733,000	9,600,000	9,600,000	9,600,000	9,600,000	9,600,000
Goal	10,074,000	10,074,000	10,074,000	10,074,000	10,074,000	10,074,000	10,074,000	10,074,000	10,074,000	10,074,000	10,074,000	10,074,000

Annual Capital   Go To [Top]

	0	1	2	3	4	5	6	7	8	9	10	11
Annual Capital **($X1000)**												
Actual	12,567	14,568	12,346	15,876	23,796	13,568	14,567	12,346	13,333	12,222	15,678	14,546
Budget	15,655	14,655	15,678	16,000	14,567	14,111	13,600	13,600	13,600	13,600	13,600	13,600
								13,000				
Installed Capacity **(MWe)**	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000
Annual Capital **($/KWe)**												
Actual	12.6	14.6	12.3	15.9	23.8	13.6	14.6	12.3	13.3	12.2	15.7	14.5
Budget	15.6	14.6	15.7	16.0	14.6	14.1	13.6	13.6	13.6	13.6	13.6	13.6

Inventory Level   Go To [Top]

	0	1	2	3	4	5	6	7	8	9	10	11
Inventory Level **($X1000)**												
Actual Monthly	30,000	29,600	30,000	30,400	28,000							
Goal Monthly	30,000	28,000	27,000	26,500	26,000	25,000	24,500	24,000	23,000	22,000	21,000	20,000

Indirect Cost   Go To [Top]

	0	1	2	3	4	5	6	7	8	9	10	11
Indirect Cost **($X1000)**												
Actual	26,000	24,000	23,676	22,343	23,333	25,432	22,123	25,546	23,678	24,576	24,567	23,678
Cents/KWh	0.27	0.27	0.27	0.23	0.24	0.26	0.23	0.27	0.25	0.26	0.26	0.25
Budget	24,000	24,000	24,000	24,000	24,000	24,000	24,000	24,000	24,000	24,000	24,000	24,000
Cents/KWh	0.24	0.24	0.24	0.24	0.24	0.24	0.24	0.24	0.24	0.24	0.24	0.24
Net Generation **(MWh)**												
Actual	9,651,605	9,000,000	8,799,000	9,600,000	9,733,000	9,733,000	9,733,000	9,600,000	9,600,000	9,600,000	9,600,000	9,600,000
Goal	10,074,000	10,074,000	10,074,000	10,074,000	10,074,000	10,074,000	10,074,000	10,074,000	10,074,000	10,074,000	10,074,000	10,074,000

Energy Price   Go To [Top]

	0	1	2	3	4	5	6	7	8	9	10	11
Energy Price **($/MWh)**												
Actual Energy Sold												
Annual Weighted Average	36.00	44.20	29.60	56.10	88.30	44.00	22.20	31.40	44.60	34.00	32.90	30.98
Goal												
Annual Weighted Average	34.00	34.20	33.00	60.00	60.00	60.00	60.00	60.00	58.00	58.00	58.00	58.00
Net Generation **(MWh)**												
Actual	9,651,605	9,000,000	8,799,000	9,600,000	9,733,000	9,733,000	9,733,000	9,600,000	9,600,000	9,600,000	9,600,000	9,600,000
Goal	10,074,000	10,074,000	10,074,000	10,074,000	10,074,000	10,074,000	10,074,000	10,074,000	10,074,000	10,074,000	10,074,000	10,074,000

Return on Investment (ROI)   Go To [Top]

	0	1	2	3	4	5	6	7	8	9	10	11
Capital Additions **($X1000)**												
Actual	14,567	12,346	12,333	13,432	17,865	18,000	19,432	15,432	14,325	12,345	13,222	12,678
Budget	16,000	16,000	16,000	16,000	14,000	14,000	14,000	14,000	13,700	13,700	13,700	13,700
Depreciation **($X1000)**												
Actual	23,457	23,678	23,679	23,400	23,400	23,400	22,876	23,412	25,777	22,345	22,254	23,807
Budget	16,897	16,897	16,897	16,897	16,897	16,897	16,897	16,897	16,897	16,897	16,897	16,897
Net Plant Investment **($X1000)**												
Prior	250,000											
Actual	245,556	239,889	234,116	239,132	226,364	223,964	221,342	217,962	212,226	207,226	202,710	197,116
Plan	249,652	249,103	248,656	248,206	246,758	246,309	243,861	242,412	240,814	239,216	237,617	236,018
Earnings **($X1000)**												
Actual	47,292	48,595	56,000	46,333	40,765	42,900	44,444	39,070	40,543	40,543	40,543	40,543
Plan	55,681	55,681	55,681	52,009	52,009	52,009	50,000	50,000	50,000	50,000	50,000	50,000
Return on Investment **(%)**												
Actual	19.26	20.24	23.92	20.22	21.54	19.15	20.03	18.29	19.10	19.56	20.00	20.57
Plan	22.31	22.36	22.39	20.96	21.08	21.20	20.50	20.63	20.76	20.90	21.04	21.18

Return on Equity (ROE) Go To Top

Data Year 0

		0	1	2	3	4	5	6	7	8	9	10	11
Capital Additions	**($X1000)**												
Actual		14,507	12,345	12,333	13,400	17,865	18,000	19,432	15,432	14,325	12,345	13,222	12,678
Budget		16,000	16,000	16,000	16,000	14,000	14,000	14,000	14,000	13,700	13,700	13,700	13,700
Depreciation	**($X1000)**												
Actual		23,457	23,678	23,879	23,400	23,400	23,400	22,678	23,412	26,777	22,345	22,254	23,667
Budget		16,897	16,897	16,897	16,897	16,897	16,897	16,897	16,897	16,897	16,897	16,897	16,897
Net Plant Investment	**($X1000)**												
Prior		250,000											
Actual		245,555	239,889	234,116	229,132	226,364	223,864	221,342	217,962	212,226	207,226	202,710	197,116
Plan		249,552	249,103	248,655	248,206	246,758	246,309	243,861	242,412	240,814	239,215	237,617	236,018
Debt Ratio	**(%)**	35	35	35	35	35	35	35	35	35	35	35	35
Equity Investment	**($X1000)**												
Actual		184,166	179,916	175,597	171,849	169,773	167,748	166,457	163,464	159,170	155,420	152,033	147,837
Plan		187,164	186,827	186,491	186,155	185,060	183,982	182,896	181,809	180,610	179,411	178,212	177,014
Earnings	**($X1000)**												
Actual		47,202	48,565	56,000	46,333	48,765	42,000	44,444	39,870	40,543	40,543	40,543	40,543
Plan		55,691	55,691	55,691	52,009	52,009	52,009	50,200	50,000	50,000	50,000	50,000	50,000
Return on Equity	**(%)**												
Actual		25.58	26.99	31.89	26.96	28.72	25.58	26.70	24.39	25.47	26.09	26.67	27.42
Plan		29.75	29.80	29.86	27.94	28.10	28.27	27.34	27.60	27.68	27.87	28.06	28.26

Maintenance Backlog Go To Top

Data Year 0

	0	1	2	3	4	5	6	7	8	9	10	11
Corrective Maintenance Backlog												
Actual Monthly	69	67	80	94	83	83	85	78	79	80	78	82
Goal Monthly	80	80	80	80	80	80	80	80	80	80	80	80

Annex V*

EXAMPLE OF PRO FORMA NUCLEAR PLANT INCOME STATEMENT (PROFIT–LOSS STATEMENT)

The following income statement was prepared as a representative example for an individual nuclear unit. With the advent of deregulation and competition in electricity markets, utilities, IPPs and generating companies are now looking more carefully at the revenues, expenses and earnings of individual and combinations of nuclear generating units. Nowadays, the practice of preparing detailed income statements at the generation company/ nuclear unit level is becoming more commonplace.

	2000	2001	2002	2003	2004
ENERGY VALUE					
Generation (MWh x 1,000)	6,503	5,899	6,485	5,899	6,503
($/MWh)	30.2	29.7	28.8	29.9	31.0
Energy Revenue	196,132	175,258	186,776	176,142	201,334
CAPACITY VALUE					
Capacity (MWe)	1,150	1,150	1,150	1,150	1,150
($/KWe)	16.7	19.0	22.7	23.5	24.4
Capacity Revenue	13,047	14,823	17,733	18,382	19,063
OPERATING REVENUE	209,179	190,081	204,509	194,525	220,397
OPERATING EXPENSES					
Nuclear O&M	38,301	54,347	41,188	58,443	44,292
A&G	11,286	11,703	12,136	12,585	13,051
Nuclear Fuel	31,556	28,984	31,898	29,379	32,421
TOTAL EXPENSE	81,143	95,035	85,222	100,408	89,764
EBITDA	128,037	95,046	119,287	94,117	130,633
DEPRECIATION	57,789	4,196	4,552	4,941	5,367
TAXES					
Federal Income	19,114	27,296	36,219	27,899	39,541
State Income	4,428	6,323	8,391	6,463	9,160
Municipal-Property	9,348	5,166	1,438	1,528	1,613
TOTAL OPERATING EXPENSES	171,822	138,016	135,821	141,239	145,445
OPERATING INCOME	37,357	52,065	68,688	53,285	74,952
INTEREST EXPENSE	1,859	1,373	1,424	1,472	1,518
EARNINGS FOR COMMON	35,498	50,692	67,264	51,813	73,434

* Annex V remains unedited.

Annex VI

DEFINITIONS AND TERMINOLOGY FOR THE NUCLEAR ECONOMIC PERFORMANCE INFORMATION SYSTEM (NEPIS)

VI–1. OBJECTIVE

The purpose of NEPIS data collection is to gather information on O&M costs on a unit and plant basis. The benefits of collecting O&M costs are compelling. It will allow management to identify more clearly where and how costs are being incurred, and to use its judgement to determine whether adjustments would improve the competitiveness of the unit.

VI–2. GENERAL INSTRUCTIONS

The NEPIS database is based on the EUCG functional O&M database; although their account numbers have been kept, their definitions have been adapted for international use. The general instructions given for the NEPIS database are given below:

- This data collection focuses on O&M costs.
- Certain nuclear unit costs should not be included in this database. They should not be reported in any sections of the survey. These costs include depreciation, interest, tax (except payroll) and regulatory body civil penalties.
- Accounting definitions are provided in Sections VI–4.1 and VI–5.3. Annex VIII (Glossary) completes this information.
- Dissimilar units (e.g. significant vintage or design differences) at the same site should be reported separately. Exceptions should be discussed and agreed with the IAEA/EUCG Task Force involved in this project. Common site or unit costs should be allocated to individual units when they are reported separately.
- All cost information provided should be on a total plant basis. Separate spreadsheets must be completed for reporting each end of cycle refuelling outage on a unit specific basis.
- Complete the information for each plant contained in your database for the reporting year. Costs common to multiple plants should be prorated.
- Costs should be reported in national currency.

— Costs should be reported for four categories: ‘labour’, ‘materials’, ‘outside services’ (external, contractors, outsource) and ‘others’. Totals will be calculated in the spreadsheet automatically.
— In all cases the data should be consistent with the best available internal corporate records. Data provided in this survey should reconcile with other published data.
— The NEPIS database is intended to provide actual data on an annual basis. Historical records will be retained.
— The reporting period should follow the calendar year from 1 January to 31 December. If data are provided for a different period, for instance when commercial operations or decommissioning took place in the reporting year, please specify this in the relevant fields (accounts 1100, 1105, 1110).
— If your plant is scheduled to go into commercial operation in a future year, please submit your initial 12 month O&M budget and label it as ‘budget information’. If your plant went operational during the reporting year, please submit your actual costs and indicate the number of units and unit months of commercial operation.
— A comment area is provided for each line of information you complete. Up to 50 characters of comments can be entered.
— Use your professional judgement to categorize your costs into these standard definitions.
— Year to year consistency of data is a long term objective of this data collection.

VI–3. DATA QUALITY ASSURANCE

A data review and verification team made up of IAEA Secretariat and EUCG Nuclear Committee (IAEA/EUCG Task Force) members will validate submittals prior to data publication. In order to facilitate this process, a self-validation feature is included in the database update program. This feature automates many of the verifications made by the review team. As you review your submittal, consider the following:

— Unusual accounting adjustments, such as amortization, large credits or change in accounting practices;
— Reasonableness of cost;
— Comparison to prior year’s data submittals;
— Inclusion/exclusion of refuelling outage costs;
— Review the submittal for missing or incomplete data.

VI–4. GENERAL PLANT AND UNIT DATA

VI–4.1. General

The plant and unit categories contain basic plant and unit[1] information and should be completed using the most current information available. All definitions and terminology used should be in accordance with the IAEA PRIS database, the source of this information.

A0001 Organizational structure

Provide the utility/plant organizational structure (schematic) for the current year (one page only).

VI–4.2. Plant specifications: A1000 to A1415

This section describes the account number, account names and definitions needed for each plant specification.

A1000 Operator [name]

The full name of the operating company.

A1010 Plant name [name]

The full name of the generating plant.

A1015 Ownership [%]

Your ownership share of the plant reported as a percentage. Note that all data submitted for jointly owned plants are to be 100% totals.

A1020 Contact person [name, address, phone, fax, email]

The name of the respondent, including telephone number and mailing address. This should be the person to contact if there are questions about the plant data.

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[1] 'Unit' is the single operating reactor at a site. 'Plant' is designated as mutiple units of identical design at one location.

A1100 Reporting start date [mm-dd-yyyy]

The reported start date is entered as mm-dd-yyyy. Use this field to report differences between the fiscal and calendar years, or for a plant/unit that starts commercial operation or decommissioning during the year.

A1105 Reporting end date [mm-dd-yyyy]

The reported end date is entered as mm-dd-yyyy. Use this field to report differences between the fiscal and calendar years, or for a plant/unit that starts commercial operation or decommissioning during the year.

A1110 Actual/budget [A/B]

The data provided should be reporting year actual. If actual data cannot be provided, please submit budget data and mark it as budget (B).

A1120 Currency used [name]

Note the national currency used when reporting cost data (e.g. Swiss franc, peseta, Indian rupee).

A1200 Operating crews [number]

The number of control room operating shift crews currently in use at the nuclear power plant.

A1205 Overtime paid to salaried staff

Indicate yes or no.

A1210 Paid base overtime [%]

Paid overtime person-hours divided by paid straight time person-hours for all utility works. Comment on different reporting methods. (Can include unplanned outage overtime).

A1215 Paid refuelling outage overtime/paid overhaul (on-line refuelling) outage overtime [%]

Paid overtime person-hours divided by paid straight time person-hours during major outage period for all utility works.

A1218 Standard work week [person-hours]

Report the number of straight time person-hours (e.g. 38 h, 44 h).

A1219 Overtime [hours]

At what hour in the week do you begin to pay overtime? Report when you begin to pay overtime, e.g. after 8 hours or after 44 hours.

A1220 Paid absence [%]

The paid absence rate expressed as a percentage of hours worked. It may include sick leave, accidents, vacations and holidays in accordance with national or local legislation.

A1230 Benefits [%]

Total payroll benefits expressed as a percentage of base payroll dollars, including paid absence. Benefits as defined here include such items as social security tax, unemployment insurance, medical benefits, housing, schooling, etc. The total payroll benefits used to calculate this percentage should also be reported in account 2502. Refer to account 2502 for a more complete definition.

Identify the benefits included in the account.

A1315 Union percentage [%]

The approximate percentage of the total workforce who are members of a recognized union.

A1320 Multiple unit operating licence [yes/no]

A response is required for multiple units only. Are your operators licensed to operate all units at the site?

A1410 Inventory [value in national currency]

Provide the total value of material and supplies in the general inventory at the year end.

A1415 Inventory pool [yes/no]

Do you utilize the services of an inventory pool?

A1420 Inventory consumption [%]

The portion of the inventory consumed divided by the total inventory at the end of the year (A1410).

VI–4.3. Unit specifications: A1600 to A2015

The terminology and definitions used in this section follow those of the IAEA PRIS database.

A1600 Unit name [name]

The name of the unit(s) reported in the O&M costs report.

A1601 Number of units [number]

The number of units reported in the O&M costs report.

A1606 Ref-unit code [code]

The same as that reported to the IAEA PRIS.

A1610 Commercial date (mm/dd/yyyy)

The commercial operation date for each unit. The commercial operation date is the date when the unit is declared officially to be in commercial operation.

A1620 Reactor type [code]

Select the appropriate reactor type from the following:

— AGR: advanced, gas cooled, graphite moderated reactor.
— BWR: boiling light water cooled and moderated reactor.
— FBR: fast breeder reactor.
— GCR: gas cooled, graphite moderated reactor.
— HTGR: high temperature, gas cooled, graphite moderated reactor.
— HWGCR: heavy water moderated, gas cooled reactor.
— HWLWR: heavy water moderated, boiling light water cooled reactor.
— LWGR: light water cooled, graphite moderated rector.
— PHWR: pressurized heavy water moderated reactor.
— PWR: pressurized light water moderated and cooled reactor.
— SGHWR: steam generating heavy water reactor.
— WWER: water cooled, water moderated power reactor.

A1630 NSSS supplier [name]

The NSSS supplier for each unit.

A1640 Maximum reference capacity [net MW(e)]

The net generation capacity for each unit.

A1645 Design electrical capacity [net MW(e)]

The net generation capacity for each unit.

A1650 Net generation [MW·h]

The actual net generation per unit in MW·h for the entire reporting year.

A1656 Annual unit capability factor [%]

This is defined as the ratio of the available energy generation (net) over a given time period to the reference energy generation (net) over the same period, expressed as a percentage. Both of these energy generation terms are determined relative to reference ambient conditions.

$$\text{UCF}\,(\%) = (\text{REG} - \text{PEL} - \text{UEL})/\text{REG} \times 100$$

where

REG is the reference energy generation (net) (MW(e)·h);

PEL is the total planned energy loss (MW(e)·h);

UEL is the total unplanned energy loss (MW(e)·h).

The total planned and unplanned energy loss is the sum of the losses from all planned and unplanned events, respectively.

A1671 Annual energy availability factor [%]

This is defined as the ratio of the available energy generation (net) over a given time period to the reference energy generation (net) over the same period, expressed as a percentage.

$$\text{EAF}\ (\%) = (\text{REG} - \text{PEL} - \text{UEL} - \text{OEL})/\text{REG} \times 100$$

where

REG is the reference energy generation (net) (MW(e)·h);

PEL is the total planned energy loss (MW(e)·h);

UEL is the total unplanned energy loss (MW(e)·h);

OEL is the total external energy loss (MW(e)·h).

The total planned and unplanned energy losses and energy loss due to causes external to the plant for the period is the sum of the losses from all planned, unplanned and external events, respectively.

A1681 Unplanned outage rate [%]

The total unplanned outage hours divided by the sum of (total unit service hours + forced outage hours) stated as a percentage for each unit.

A1690 Unplanned loss capability factor [%]

This is energy that was not produced during the period because of unplanned shutdowns, outage extensions, or unplanned load reductions owing to causes under plant management's control. Causes of energy losses are considered to be unplanned if they are not scheduled at least four weeks in advance.

UCLF (%) = (UEL/REG) × 100

where

REG is the reference energy generation (net) (MW(e) ·h);

UEL is the total unplanned energy loss (MW(e) ·h).

A1700 End of cycle refuelling outage start date [mm/dd/yyyy]

The refuelling outage start date should be entered as mm/dd/yyyy.

A1710 End of cycle refuelling outage end date [mm/dd/yyyy]

The refuelling outage return to service date should be entered as mm/dd/yyyy. Note: Even if your outage end date goes into the next year, use 12/31/yyyy as the end of cycle date.

A1715 Refuelling or annual maintenance outage duration

Note that this field will be autocalculated according to accounts A1700 and A1710.

A1720 Incremental refuelling or annual maintenance outage cost [national currency]

The incremental O&M outage costs of the most recently completed refuelling outage (even if it spans more than one year). See the refuelling outage cost definitions. Note: Refer to A1710 for refuelling outage end date.

A1750 Operating cycle (12, 18, 24, etc.) [number]

The duration, in months, of the operating cycle, i.e. the time between two refuelling/overhaul outages (12, 18, 24, etc., months). Note that you can enter any required number.

A1800 Original capital cost [national currency × 1000]

The original capital cost of the facility when first put into commercial operation, excluding the interest during construction. If the plant is sold and revalued please state the revalued cost.

A1810 Current annual investment/capital [national currency × 1000]

All costs associated with improvements and modifications made during the reporting period (i.e. the additional capital investment made during the current reporting period, excluding interest). These costs should include any designs, installations, removals or salvages made during the reporting period. Other miscellaneous investment/capital additions, such as those for facilities, computer equipment, moveable equipment or vehicles, should also be included. These costs should be fully burdened with indirect costs. Exclude interest during construction. (Multiples of 1000).

A1820 Total investment/capital additions [national currency × 1000]

The capital improvements and modifications made since the unit was placed in commercial operation, excluding interest during construction and retirements. Note that this amount should equal the sum of the value reported last year for account A1820 and the current year value shown in account A1810. (Multiples of 1000).

A1900 Nuclear fuel cost (total) [national currency × 1000]

The total of accounts A1901, A1902 and A1903. These are the total costs associated with the nuclear fuel which is burned up during the reporting period, separated into three categories: A1901, A1902 and A1903. This cost is based upon the amortized costs associated with the purchase of uranium, and the costs of conversion, enrichment and fabrication services, along with storage and shipment costs and inventory (including interest) charges less any expected salvage value. Also included should be payments of decommissioning and decontamination charges, as well as current and prior spent nuclear fuel disposal costs (both principal and interest). You may enter this value and not the specific values in accounts A1901, A1902, A1903. (Multiples of 1000).

A1901 Direct fuel costs [national currency × 1000]

The direct amortized cost of the fuel load, including the purchase of uranium, its conversion, enrichment, fabrication services, design analysis, and shipping and storage charges (for CANDU's include the costs associated with heavy water replenishment). (Multiples of 1000).

A1902 Fuel financing costs [national currency × 1000]

The indirect financing cost of the fuel load, lease financing charges and the carrying costs. (Multiples of 1000).

A1903 Fuel regulated and other costs [national currency × 1000]

The regulated and other amortized cost of the fuel load, including decommissioning and decontamination charges, current and prior spent fuel disposal costs, and amortization of the final core cost. (Multiples of 1000).

The accounts listed above deal with cost information.

A1904 Design effective full power days [dd]

Design effective full power days for the current fuel load.

A1920 Operating life [yyyy]

The number of years the plant is licensed for or, if more appropriate, the designed lifetime.

A1925 Most recent full cycle start date [mm/dd/yyyy]

Using the last fully completed cycle, the beginning of that cycle's power production or the end of the last refuelling outage. For PHWR and CANDU type reactors, this is the start date of the major planned outage.

A1930 Most recent full cycle end date [mm/dd/yyyy]

Using the last fully completed cycle, the end of that cycle's power production or start date of the next refuelling outage. For PHWR and CANDU type reactors, this is the end date of the major planned outage.

A1935 Most recent full cycle unit capability factor [%]

The capability factor for the entire cycle (the time period between the finish and start of the last refuelling outage).

A2000 Annual decommissioning funding [national currency × 1000]

Enter the amount of your unit's annual contribution or accrual to provide for the cost of decommissioning, if applicable. State in current year money and do not include annual interest earned. Note: Reporting total unit contributions will require input from your co-owners (if it is a jointly owned project). It is important that this information be obtained, because for comparability a 100% number is required.

A2010 Decommissioning cost estimate [national currency × 1000]

Provide the estimated total cost for decommissioning. Specify the type of decommissioning in the comments (e.g. prompt removal/dismantling of the unit). This should be the total estimated cost, not the amount accrued in the fund. This should be in currency of the year that the most recent formal cost estimate was made; do not escalate to current year money. This should be the total cost estimate for a unit, not a utility's share or a jurisdiction's portion — add a field or comment.

A2011 Year of cost estimate [yyyy]

State the year in which the decommissioning cost estimate was made. This is the year of the currency reported above in account A2010.

A2015 Nuclear insurance premiums [national currency × 1000]

Provide the total nuclear insurance premiums (for nuclear liability, property and any extra expense premiums) for the reporting year. Provide this amount per plant, using any appropriate means of unitizing the plant or station premiums. Barring any better basis for such allocation, consider dividing station premium by the number of units at the station. Do not include refunds or recoveries.

A2110 Low and medium radioactive waste distance from plant [km]

Indicate if radioactive waste is stored at the plant or transported elsewhere. If it is transported, indicate the distance from the plant to the storage facilities in kilometres.

A2120 High radioactive waste distance from plant [km]

Indicate if radioactive waste is stored at the plant or transported elsewhere. If it is transported, indicate the distance from the plant to the storage facilities in kilometres.

VI–5. O&M COST DEFINITIONS

VI–5.1. Overview

- The data provided should reflect the full direct cost of operating and maintaining the nuclear plant given in account 2000 of the annual spreadsheet. This should include all the costs from the senior nuclear corporate officer down, plus other identifiable direct costs.
- The plant indirect costs should be reported in accounts 2500–2503, separate from the functional breakdown of direct costs (accounts 1099–2000). These costs should reflect the share of payroll taxes and benefits and the corporate administrative and general costs applicable to the nuclear plant. Costs that would be applicable if the plant were considered a business unit should be included.
- All costs should be submitted in multiples of thousands of the national currency.
- All data reported in this section should be reported on a plant basis. However, as previously noted, separate data should be submitted for dissimilar units at a single site. See Glossary for definition of plant.
- All data in this section should include all costs related to normal operations, maintenance and outage periods.
- All labour costs submitted should include paid absence but exclude benefits.
- The full direct cost to operate and maintain the plant should be broken down in accordance with accounts 1099–1399. They are automatically totalled in account 2000.

— Capital expenditures during the year should be reported separately in account 3000. The total capital in account 3000 should match the total of the unit capital costs reported in account A1810 in the plant spreadsheet.

VI–5.2. Resource definitions

— Labour: This includes all direct utility payroll costs, both on-site and off-site, plus shift and overtime premium pay (including paid absence but excluding other benefits).
— Materials and equipment: This includes all materials used and consumed during plant operations, maintenance, testing and monitoring. Include consumed operational spares (i.e. the cost of spare parts) and other miscellaneous equipment. Also include fuels, oils, chemicals and gases, resins, general office supplies, as well as other miscellaneous materials and consumables. Include purchasing and material handling overheads if, and only if, they are not already accounted for in account 1340.
— Outside services: This includes the cost of services performed by outside firms. General categories include, but are not limited to, craft support, data processing, technical or engineering services, security and management consultancy.
— Other: This includes all other costs not provided for in the labour, materials and equipment, and outside services categories. Specifically includes travel, staff development, regulatory fees, utilities and internal company services such as computer equipment, microfilming and duplicating.

VI–5.3. Account definitions: 1099–3004

This section describes the account ID, organization, function and definition of each account ID for all the accounts.

The following definitions provide the basis for categorizing the cost data. The cost data should reflect the total O&M direct costs for labour, materials, equipment and the outside services/functions shown below.

Capital additions costs should not be included in accounts 1099–2000. These costs should be reported in account 3000. Indirect costs should be reported in accounts 2500–2503.

VI–5.4. Operations costs

1099 Operations (total) [national currency × 1000]

The activities associated with the operations function includes:

— Control room licensed and unlicensed operators;
— Equipment tagging processes;
— Operations procedures;
— Fuel handling personnel/management and supervision;
— Control room technical shift advisers;
— Process gases, fuels and resins;
— Shift operating managers;
— Off-site power costs (put in account 1099 under ‘other’ cost category).

VI–5.5. Maintenance costs

1110 Preventive maintenance (mechanical and electrical) [national currency × 1000]

The activities associated with forestalling or preventing anticipated problems or the breakdown of a system, part, etc.; for example:

— Maintenance procedures;
— Recalibrations;
— Work package planning and preparation;
— Obtaining/preparing work permits for work packages;
— Reviewing completed work packages;
— Machine shop services;
— Lubrication programmes;
— Interval replacements of equipment components;
— Tool room activities.

1115 Preventive maintenance (instrumentation and control) [national currency × 1000]

The activities associated with forestalling or preventing anticipated problems or the breakdown of a system, part, etc.; for example:

— Supporting plant process instrumentation;
— Supporting plant process computer systems;

— Work package planning and preparation;
— Obtaining/preparing work permits for work packages;
— Reviewing completed work packages;
— Lubrication programmes;
— Recalibrations;
— Interval replacements of equipment components.

1117 *Preventive maintenance, subtotal (1110 + 1115) [national currency × 1000].*

1120 *Corrective maintenance (mechanical and electrical)*

Activities associated with the repair or replacement of plant systems, equipment, components, etc., which are found to be defective, and repairing, altering, adjusting, or bringing them into conformity or making them operable, including:

— Maintenance procedures;
— Recalibrations;
— Work package planning and preparation;
— Obtaining/preparing work permits for work packages;
— Reviewing completed work packages;
— Machine shop services;
— Tool room activities.

1125 *Corrective maintenance (instrumentation and control)*

Activities associated with the repair or replacement of plant systems, equipment, components, etc., which are found to be defective, and repairing, altering, adjusting or bringing them into conformity or making them operable, including:

— Supporting plant process instrumentation;
— Supporting plant process computer systems;
— Work package planning and preparation;
— Obtaining/preparing work permits for work packages;
— Reviewing completed work packages.

1127 *Corrective maintenance subtotal (1120 + 1125)*

1128 Preventive and corrective maintenance subtotal (1117 + 1127) [calculated field]

1130 Surveillance testing (mechanical and electrical) [national currency × 1000]

Verification of safe operability and compliance with regulatory requirements and commitments, such as:

— Calibration and functional testing of equipment;
— Measuring and test equipment programme:
— Safety systems tests;
— Tool room activities.

1135 Surveillance testing (instrumentation and control)

Verification of safe operability and compliance with regulatory requirements and commitments, such as:

— Instrument and control surveillance;
— Calibration and functional testing of equipment;
— Measuring and test equipment programme;
— Instrumentation and control procedures;
— Safety systems tests.

1137 Surveillance testing subtotal (1130 + 1135)

1140 Non-capital modification

Include all the non-capital modification costs not included in accounts 1099–2000. Examples: (1) in France, any modification which improves efficiency is considered capital investment, therefore, it is not included in the O&M costs; (2) a change of steam generator is considered a capital modification, therefore, it should not be included here.

1199 Total maintenance [calculated field]

Total maintenance cost as defined by the preceding functions (accounts 1128, 1137 and 1140). This is a calculated field.

VI–5.6. Support services

1210 Technical/engineering

All costs associated with the following technical/engineering activities:

- Non-destructive examination;
- In-service inspection programmes;
- Engineering support of licensing;
- Estimation services;
- Plant modification activities;
- Engineering analysis, operability, evaluations;
- Performance monitoring/analysis;
- Administrative controls for design control, configuration control, engineering evaluations;
- Code compliance (ASME, NFPA, IEEE, or others as applied in your country);
- Prepare requests for financial approval of new projects;
- Site environmental qualification programme;
- Snubber surveillance programme;
- Site fire protection engineering;
- Engineering resolution of material problems;
- Plant design basis documents;
- Engineering databases, software controls, personnel qualification for computer programs;
- Systems engineering;
- Point of contact for INPO, WANO or other organization activities;
- Integrated containment leak rate test programme;
- Support for maintenance and operations;
- Support contractor coordination;
- Prepare and maintain assigned plant procedures;
- Safety system unavailability monitoring and monthly plant operating reports;
- Trending of system and component performance;
- System review for root cause of failure determinations;
- Post-modification retest, surveillance testing, special test preparation;
- Spare part evaluations;
- Incident report responses;
- Predict failure of rotating equipment;
- Predict secondary system equipment thermal performance efficiency losses;

— Erosion/corrosion programme;
— Repair and replacement programme (e.g. ASME XI);
— Repair alteration programme (e.g. ASME VIII);
— Evaluation of site radiography;
— Evaluation of site ultrasonic examinations;
— Local leak rate testing;
— Prepare design packages for modifications and new designs;
— Revise drawings, manuals and computer databases to maintain plant configuration;
— General drafting support;
— Commercial grade material for nuclear safety related applications;
— Research and respond to material problems as identified by the regulatory body, supplies and industry;
— Seismic qualification programme;
— Equipment lubrication programme;
— Reliability centred maintenance review;
— Design basis documentation.

Note: If design basis documentation is capitalized by your utility, include in capital portion of database and do not include here.

1212 Fuels management

— Nuclear fuel management (including core configuration and core performance and evaluation, not included in account 1900):
— Reload core physics design activities;
— Core follow modelling and assessment;
— Provide support for reload licensing involving enrichment or configuration;
— Monitor and evaluate fuel performance;
— Nuclear fuel procurement, market analysis, procurement;
— Fuel cost economic analysis, fuel budgeting;
— Fuel fabrication contract administration, fabrication audit support.

1214 Licensing

All costs associated with licensing and with regulatory agencies.

Note: Any fees should be entered in account 1214 ‘other’ category and not in ‘labour’, ‘materials’, or ‘outside services’.

— Final safety analysis report, change notices, annual updates;
— Processing of operating licence amendment requests;
— Technical support of NSSS owner's group;
— Coordination of responses to regulatory body bulletins, generic letters;
— Environmental technical specification (tech spec) issues;
— Incident programme — reportability review;
— Licensee event reports and reports to regulatory agencies;
— Coordinate support of regulatory body inspections and respond to findings;
— Regulatory body annual fees;
— INPO/WANO dues.

1219 Technical/engineering services subtotal [calculated field]

Total of accounts 1210, 1212 and 1214. This is a calculated field.

1220 Nuclear training

All costs associated with technical training (excluding student salaries, which are included with each function). Primarily, the development, instruction and evaluation of the following training activities: licensed and non-licensed operator training; health physics/chemistry; emergency preparedness; security, technical, maintenance and craft qualifications; general employee training and simulator support costs. It might include:

— INPO or other organization accredited classroom training:
  - Senior reactor operator, initial and requalification;
  - Reactor operator, initial and requalification;
  - Shift technical adviser;
  - Non-licensed operator;
  - Health physics technician;
  - Chemistry/radioactive waste technician;
  - Mechanical maintenance mechanic;
  - Instrument/control technician;
  - Technical staff and managers (excluding management training);
  - Instructor.

— Other classroom training programmes:
  - General employee training;
  - Security;
  - Emergency preparedness training;
  - Fitness for duty training;

  - Continued employee observation;
  - Hazard aid/cardiopulmonary resuscitation;
  - Radioactive chemical helper;
  - Quality assurance engineers;
  - Plant computer.
- Training conducted by outside organizations:
  - Maintenance contractors;
  - Apprenticeship training;
  - Quality control inspectors;
  - Management training;
  - Fire brigade training.
- Prepare and maintain training department procedures.
- Operate and maintain control room simulator:
  - Software support;
  - Repair and maintenance of the simulator;
  - Configuration control to assure certification.
- Process personnel for training and other functions requiring unescorted access to plant.
- Training or qualification status.

1230 Security

All costs associated with plant security, including management/supervision, guards and other security functions. It might include:

- Providing physical security for the plant;
- Testing and operating the intrusion detection and assessment system;
- Performing background investigations;
- Administering contract with security agency;
- Security clearance for plant access;
- Guards;
- Management and supervision.

1240 Radiation protection/health physics

All costs associated with the following health physics activities: routine monitoring, exposure control and decontamination programmes, ALARA programme implementation, instrument calibration and control. It might include:

- Radiation exposure control programmes;
- Radiation work permits;

— Radiological surveys and posting;
— ALARA programme;
— Temporary shielding;
— Instrument calibration and control of radioactive materials and sources;
— Contamination control within radiologically controlled areas;
— Laboratory radioactivity counting and analytical equipment;
— Respiratory protection programme;
— Calibrate, maintain, operate portable radiation survey equipment, whole body contamination monitors, laundry and continuous air monitors;
— Radioactive effluent release monitoring and dose calibrations;
— Health physics procedure maintenance;
— Environmental monitoring programmes;
— Health physics records, access control and gamma spectroscopy computer systems;
— 'Hot' particle programme.

1245 Radioactive waste monitoring/decontamination

Also include in this category radioactive waste disposal fees (excluding fuel). It might include:

— Gaseous radioactive waste system;
— Operate evaporators and filters to process liquid radioactive waste;
— Sort, compact, package dry radioactive waste for off-site burial;
— Change out, package radioactive filters and resin for off-site burial;
— Discharge radioactive liquids that meet regulatory limits for off-site disposal;
— Decontaminate plant tools and equipment;
— Decontamination activities launder and restock protective clothing inventories;
— Low level waste volume reduction;
— Radioactive waste disposal fees (excluding fuel);
— Shipping fees.

1249 Radiological waste/health physics subtotal

Total of accounts 1240 and 1245. This is a calculated field.

1250 Quality assurance

All costs associated with the quality assurance programme involved in operational quality assurance. It might include:

— Quality audits of plant activities and vendors;
— Operational quality assurance;
— Quality surveillance of plant activities;
— In-line review of documents and procedures;
— Maintenance programme manuals and quality assurance procedures;
— Management assessments for quality assurance issues;
— Provide for authorized nuclear inspection activities;
— Administer vendor verification programme;
— Corrective action programme — action assignment, tracking to closure and trending.

1252 Quality control

All costs associated with quality control involved in plant inspection activities, including non-destructive examinations, receiving inspections, plant modification surveillance. It might include:

— Visual inspection;
— Non-destructive examination or tests;
— Tech spec surveillance on safety related systems (e.g. snubbers and fire barrier seals);
— Inspection of maintenance modifications activities;
— Material receipt inspections;
— Review and reporting of nuclear reliability data system;
— Non-compliance report processing;
— Review and closeout of work request and preventive maintenance;
— Task sheets;
— Performance of material testing for commercial grade dedication programme.

1254 Nuclear safety assessment

Activities might include:

— Internal and external operating experience, reviewed and disseminated;
— Independent safety engineering group activities;
— Human performance reviews;
— Significant event reduction programme coordination and review;
— Safety analysis support of new core designs, plant occurrences and safety related set point changes;

— Independent plant evaluation studies;
— Plant risk and reliability studies.

If you cannot specify the number for an account, mention in the comments.

1259 Quality assurance/quality control subtotal [calculated field]

Total of accounts 1250, 1252 and 1254. This is a calculated field.

1270 Chemistry

All costs associated with station chemistry programmes, routine chemistry monitoring, analysis and control. It might include:

— Analysing and maintaining all plant water and steam chemistry;
— Maintaining process and laboratory chemical instrumentation;
— Operating plant chemical addition equipment and making up demineralizers;
— Administering chemical control programme;
— Routine chemistry monitoring, analysis and control;
— Costing of chemicals.

1299 Support service costs total [calculated field]

Support service costs (total) defined by the preceding functions (accounts 1219, 1220, 1230, 1249, 1259 and 1270). This is a calculated field.

VI–5.7. Plant administration

1310 Plant administration management

All costs for the plant administrative management: manager/superintendent and staff, human resources (including industrial safety), financial/budget (including contract administration), plant communications, performance evaluation and fire protection.

Note: Managers' costs belong in the function they manage (i.e. engineering, maintenance, quality assurance, etc., if that is their sole responsibility). This category is for those management positions that are not functionally addressed elsewhere in the database. It includes all administrative management that provides support directly to or that works at the nuclear power plant. It might include:

— Senior nuclear officer, general manager, plant manager.
— Administrative staff for senior nuclear officer.
— Plant personnel functions:
  • Labour and employee relations;
  • On-site recruiting services;
  • Fitness for duty programme (excluding training).
— Financial services:
  • Budget preparation and overview;
  • Work order programme support;
  • Industrial safety programme;
  • Plant administration;
  • Plant mail service;
  • On-site medical.
— Contract administration:
  • Engineering and maintenance outside services;
  • Direct material purchases.
— Plant communications.
— Performance evaluation.
— Fire protection.
— Visitors centre maintained by plant administration.
— Community support maintained by plant administration.

1312 Planning and scheduling

— Develop and coordinate daily work scheduling;
— Prepare, schedule and track plant surveillance programme and mode change letters;
— Long range work planning (not financial business).

1314 Outage support

Preparation, development and coordination of planned plant refuelling outages and scope of work activities. This includes development and coordination of daily work schedule during outages.

Note: This is not the incremental outage cost. See Section VI–5 on refuelling outage cost definitions.

1319 Plant management subtotal [calculated field]

Total of accounts 1310, 1312 and 1314. This is a calculated field.

1320 Records management

All costs associated with the receipt, preparation, encoding, verification and filing of records and documents for the following: plant design verification, O&M manuals and general plant records. It might include:

— Maintaining controlled documents;
— Receiving, inspecting, filing, maintaining and retrieving plant records;
— Microfilming plant records and drawings;
— Providing reproduction services;
— Providing supplemental word processing support;
— Reproducing and distributing plant procedures and controlled documents;
— Maintaining plant libraries;
— Reproducing and distributing O&M manuals, such as vendor manuals, procedure manuals, etc.

1325 Nuclear information services

All costs associated with plant computer operations and support. It might include:

— Maintaining and operating plant data centre, information systems network and help desk;
— Planning and implementing information computer system hardware and software enhancements and growth management;
— Providing technical support for specialized application systems and software;
— Providing acquisition and technical support for PC based hardware and software systems;
— Providing technical support for data circuits and specialized information system hardware;
— Developing, implementing and maintaining in-house application programs and systems.

1330 Emergency planning (EP)

All costs associated with EP development, training and conducting drills and providing interface with federal, state and local emergency organizations.

Note: Any fees associated with EP should be entered in account 1330 'other' category and not in 'labour', 'materials', or 'outside services'. It might include:

— Scenario development;
— Coordinating plant EP affairs with those of state, county and local community organizations;
— Planning and conducting EP drills and exercises;
— Providing EP training for off-site organizations;
— Developing and maintaining EP plans and procedures;
— Developing and maintaining EP facilities (TSC, emergency operation facility, JPIC);
— Negotiating and administering fees and expenses paid to others for EP activities;
— Coordination of efforts associated with hazardous material emergencies;
— Maintaining the programme for notification of plant personnel to staff emergency response positions;
— Maintaining a public alert system for notifying the general public of a radiological emergency;
— For US plants, expenses associated with Federal Emergency Management Agency fees, and state and county assessments and activities. For other countries enter comparable expenses for similar activities.

1340 Stores

All costs associated with warehousing (to administer plant/utility inventory). Includes procurement associated costs when directly in support of the process. Also includes purchasing and materials support costs that are not part of a materials or procurement overhead. It might include:

— Soliciting bids;
— Preparing procurement packages;
— Interfacing with suppliers and contractors;
— Expediting purchases;
— Receiving, storing, issuing and delivering material and supplies;
— Creating and processing requisitions for stock;

— Maintaining storage area and off-site shipping of non-radioactive hazardous material that is returned to the storeroom;
— Administering purchase of material and supplies;
— Resolving vendor claims.

Storeroom costs incurred during the reporting period are more appropriately accounted for in this category rather than as a material overhead.

Note: If your company includes storeroom costs as a part of the stores/material overheads, make sure these costs are not recorded twice in the survey. However, if there is a difference between reporting year storeroom cost and the amount of storeroom cost charged to issued material, enter the difference in this account. It can be a negative or a positive value.

Material costs should be reported under the appropriate function. Inventory costs are investments and should not be included here.

1350 Housekeeping

Cost expended on general plant cleanup. It might include:

— Providing plant helpers and supervisors for miscellaneous semi-skilled labour;
— Landscaping and snow removal;
— Vehicle maintenance personnel (identify if contract maintenance);
— Rent and maintenance for off-site office or service buildings;
— Janitorial services;
— Sewage treatment;
— Removal of non-radioactive waste and rubbish from the site;

Maintenance of non-power block buildings and grounds including parking lots.

1360 Miscellaneous/other

Include here the costs of general clerical support when not identifiable with a specific function (e.g. word processing, duplicating).

Note: Clerical support for specific work functions is to be included with each function.

— General clerical support not identifiable with a specific function;
— Other labour that cannot be categorized with a specific function.

Also include here costs that cannot be allocated to any of the other plant administration categories.

1399 Plant administration total [calculated field]

Total plant administration costs as defined by the preceding functions (accounts 1319, 1320, 1325, 1330, 1340, 1350 and 1360). This is a calculated field.

VI–5.8. Direct and indirect costs

2000 Direct O&M total [calculated field]

Total of items 1099, 1199, 1299 and 1399. This is a calculated field.

2500 Indirect costs total [calculated field]

Total of accounts 2501, 2502 and 2503. This is a calculated field.

For those units not providing total indirect costs (A&G), an approximation of 24% of the total O&M direct costs will be used. The approximation of 24% was obtained by averaging the ratio of A&G to O&M for 65 units over the past three years. Only tax incurred on O&M costs is reported here.

2501 Indirect costs — insurance portion

Insurance, including liability, property, replacement power, etc. This number should match A2015, nuclear insurance premiums.

2502 Indirect costs — pension and benefits portion and payroll tax

Cost of direct payments or company paid employee related insurance for any activity benefiting the employee. It includes such items as:

— Accident or death benefits;
— Sick leave;
— Hospitalization;
— Medical insurance;
— Recreational allowances or facilities;
— Relocation expenses;

— Severance or retirement incentives;
— Performance incentive payments;
— Dependant care;
— Education reimbursement;
— Company supported or matched savings funds;
— Long term disability;
— Benefit related administrative expenses (employee housing, facilities, etc.);
— Payroll tax — tax based on payroll to provide for unemployment insurance, social security and other benefits.

This number should also be reported in A1230 (benefits).

2503 Indirect costs — other

Nuclear and corporate A&G expenses which would be allocated to nuclear. These typically include:

— Corporate executive functions;
— Corporate procurement and contract administration;
— Human resources (personnel);
— Payroll, accounts payable and other corporate accounting;
— Computer operations (not including nuclear account 1325, nuclear information services);
— Community relations (not directly maintained by plant administration);
— Vehicle and equipment services;
— Legal services;
— Duplicating and printing services;
— Landlord costs (facilities management);
— Library and mail services;
— Fixed asset accounting.

3000 Capital total [national currency × 1000]

Include here the total capital expenditure for the current year broken down by category: ‘labour’, ‘materials and equipment’, ‘outside services’ and ‘other’. The cost reported here should be the sum of the cost reported in A1810 (current year capital) for each plant unit and relate to cash expenditures not ‘to closed to plant’ or the used and useful concept.

VI–6. REFUELLING/OVERHAUL OUTAGE COST DEFINITIONS

Unit refuelling outage cost data are organized in a similar format to that of the plant O&M data included in the functional cost section of the database. Except as noted, functional account numbers 1099–2000, their descriptions, resource categories and account definitions used to categorize the unit refuelling/overhaul outage cost in this section are identical to those used in the plant O&M functional cost section and the ‘annual’ section of the electronic update spreadsheet. If your outage costs cannot be categorized within these detailed accounts, please enter costs in the subtotal or total accounts where applicable.

VI–6.1. Overview

The purpose of this section is to identify only the ‘incremental’ or additional direct O&M costs incurred during the reporting period in performing a refuelling outage at a nuclear power unit. Although refuelling outage costs are included in the O&M functional cost accounts 1099–2000, incremental O&M costs attributed to unit refuelling outage are not specifically identified. Typically, incremental outage costs include the additional labour, materials and equipment, outside services and other costs incurred by a functional group in supporting a refuelling outage beyond what would have been expended during the reporting period had the outage not occurred. For example, the additional or incremental overtime required by utility maintenance personnel to support a unit refuelling outage would be included as a labour cost in this section. The normal or base straight time labour cost of the same maintenance personnel would not be included. The additional or incremental outside service cost for contractors hired only to support the refuelling outage would be included as an outside services cost in this section.

- Costs and information included in this section are only those attributed to, or are the result of, a unit specific refuelling outage.
- The refuelling/overhaul outage electronic spreadsheet should be used to input information for this section. Note that the unit number associated with the refuelling outage and the outage start and end dates must be entered when adding a new outage to the database.
- Only refuelling/overhaul outage costs incurred during the reporting period (through 12/31/yyyy) should be included. If the refuelling outage extends into the following year, the remaining outage costs should be included in next year’s submittal.

— The refuel outage start date, end date and duration should be identical to the dates and duration entered in corresponding unit accounts A1700, A1710 and A1715, respectively.

Annex VII

GLOSSARY OF BUSINESS LITERACY TERMS

A&G costs. Administrative and general costs: corporate overhead costs (indirect costs) covering items such as pensions, benefits, legal, human resources, tuition refunds, transportation and similar costs.

above the line. Expenses borne by a ratepayer.

accelerated depreciation. Any depreciation method resulting in greater amounts of depreciation expense in the early years of a plant asset's life and lesser amounts in later years. Examples are double-declining-balance and sum-of-the-years'-digits methods.

accounting entity. The business unit for which financial statements are being prepared. An accounting entity may be a complete business, such as a partnership or a corporation, or a smaller unit of a business, such as a subsidiary or division.

accounting equation. The equation reflected in the balance sheet:

accrual. Recognition of an expense (or revenue) and the related liability (or asset) that is caused by an accounting event, frequently by the passage of time, and that is not signaled by an explicit cash transaction. For example, the recognition of interest expense or revenue (or wages, salaries, rent) at the end of a period even though no explicit cash transaction were made at that time.

accumulated depreciation. The cumulative amount of depreciation recorded against an asset or group of assets during the entire period of time the asset or assets have been owned.

allowance for funds used during construction. A non-cash item representing the estimated composite interest costs of debt and a return on equity funds used to finance construction. The allowance is included in the property accounts; the contra credit is included in income. This portion of the carrying value of property (along with the rest) is included in a utility company's rate base and is recovered through revenues over its useful life.

allowed (allowable) rate of return. The rate of return (to be determined to rate base) which the regulatory commission sets to determine rates.

amortization. The general process of allocating acquisition cost of assets to either the periods of benefit as expenses or to inventory accounts as product costs. Termed depreciation for plant assets, depletion for wasting assets (natural resources) and amortization for intangibles. Also used for the process of allocating premium or discount on bonds and other liabilities to the periods during which the liability is outstanding.

amortize. The periodic writing off as an expense a share of the cost of an asset, usually an intangible asset.

asset. A property or economic resource owned by an individual or enterprise.

asset allocation. The allocation of investment funds to different assets or groups of assets.

asset management. A process for making resource allocation and risk management decisions at all levels of a business to maximize profitability and value for all stakeholders.

availability. The percentage of time in a period that a power plant is available for operation.

balance sheet. The financial statement of a firm that lists the assets and liabilities at a point in time.

basic income tax. Tax consisting of the annual income tax levied upon the company by federal and state governments. Revenues received for payment of O&M expenses are not subject to income tax since, in computing taxable income, they are recognized as deductions. Depreciation is also a recognized deduction. The portion of the return element attributable to interest on debt is also deductible. On the other hand, the portion of the return element attributable to earnings on preferred and common stock is not deductible and therefore is subject to income tax. Since the income tax element is a function of the return element, it is a variable — being greatest initially and then declining over the years as the return element declines. The tax element, like the return element, is re-expressed in terms of an equivalent level annual amount.

basis. In general, the cost of a purchased asset less any depreciation previously allowed or allowable for tax purposes.

below the line. Expenses borne by a stockholder.

benchmarking. Process of identifying best practices by comparing one's own performance to the best in the industry. Comparisons include process performance (cycle time and efficiency) and cost measures, as well as other indirect measures of performance. Benchmarking strives to improve one's own practices by encouraging emulation of the top performers.

betterment. The replacement of an existing asset portion with an improved or superior asset portion.

book costs. Original cost of property, as reflected in utility company records.

book depreciation. The amount of money that must be set aside annually to recover the capital cost over the anticipated life of the facility. There are several methods of depreciation; emphasis will be upon the 'straight line' method. Using the straight line system of depreciation, this component is constant each year.

book value. The carrying amount for an item in the accounting records. When applied to a plant asset, it is the cost of the asset minus its accumulated depreciation.

break even point. The point at which money is neither being gained nor lost.

budget. A formal plan for the approval and coordination of resources.

busbar cost. The total cost associated with supplying electricity at a generating station. Components include O&M costs, fuel expense, capital carrying costs, decommissioning costs and A&G costs. These costs are usually expressed in cents per kilowatt-hour.

business improvement. Processes incorporated into a business in order to improve the results and efficiencies of the business operations.

business literacy. Understanding and awareness of business/financial terminology and the application of this understanding to daily processes.

business plan. A document linking overall corporate strategic goals and objectives to everyday work processes, including major steps about how to achieve them.

capacity factor. The power produced in a period expressed as a percentage of the maximum power a generating unit is capable of producing in that period.

capacity. The load for which a generating unit, generating station, or other electrical apparatus is rated either by the user or by the manufacturer. The ratio of the actual output divided by the ideal output is called the capacity factor. Primary capacity factors are maximum dependable capacity, based on a reference test of the unit, and design engineering reference, based on nominal plant design rating.

capital asset. Any item of property except (1) inventories, (2) trade notes and accounts receivable, (3) real property and depreciable property used in a trade or business, (4) copyrights or similar property, and (5) any government obligation derived within one year and issued at at discount.

capital budgeting. The plan for the coordination of resources and expenditures that will determine the projects a firm should undertake.

capital expenditure. An expenditure that increases net assets and provides value to consumers for a period in excess of one year.

capital intensive. A term used to designate a condition in which a relatively large dollar investment is required to produce one dollar of revenue. The electricity industry, for example, has an investment of about $4.00 for each dollar of revenue generated annually.

capital structure. The mix of different securities issued by a firm.

capital. The costs associated with an investment in a facility that is usually financed and can be depreciated. The capital return on investment and depreciation, and return of investment are amortized over the life of the investment as an expense.

capital intensive business. An enterprise that requires a significantly greater investment in facilities than do other businesses.

capitalization. Long term debt, preferred stock and owners' equity.

carrying costs. The annual cost to maintain inventory and service the cost of capital investment.

cash flow. The difference between cash receipts and cash disbursements over a specified period of time.

cash flow statement. A financial statement consisting of cash receipts and disbursements, summarizing the organization's net cash position. It reveals the sources and uses of a company's cash.

common capital stock or common stock. Shares of stock issued and stated at par value, stated value, or the cash value of the consideration received for such no par stock, none of which is limited nor preferred as to distribution of earnings or assets.

common dividends. A payment to common stockholders.

competition. Freedom of economic choice in the buying, selling, or exchange of goods and services.

competitive business intelligence. The review and analysis of publicly available information which, when assessed and disseminated to management, may create value for the business.

competitive drivers. Factors that may impact, either directly or indirectly, a strategy or business plan. These could include such items as changes in the law, innovation, the entrance of new competitors and mergers and acquisitions within the industry.

complete market. Market in which investors can buy or sell combinations of securities and/or commodities that pay off in all desired states, i.e. in all desired circumstances.

composite depreciation. Group depreciation of dissimilar items.

composite life method. Group depreciation for items of unlike kind. The term may be used when a single item, such as a crane, which consists of separate units with differing service lives, such as the chassis, the motor, the lifting mechanism, and so on, is depreciated as a whole rather than treating each of the components separately.

confiscatory return. A return so low as to deprive a utility company of its lawful property rights.

consolidated financial statement. Combined balance sheets, income statements and statements of cash flows of a parent company and its subsidiaries.

consolidated tax savings. Savings achieved by corporations that are members of an affiliated group which may file a single consolidated income tax return.

construction work in progress. Plant or assets not yet operational, which may or may not be included in a utility's rate base.

controllable costs or expenses. Costs over which the manager has control as to the amounts incurred.

cost management. Controlling and being acutely aware of the expenses incurred in and/or required to operate a business.

cost of capital. The composite rate of cost for debt interest, preferred stock dividends and common stockholder earnings requirements. It is the composite of the cost of the various capital sources used to provide the facilities utilized in supplying utility service.

cost of capital (net). The return asked, or being asked, by investors for the use of their money, expressed as percentages of the capital funds.

cost of removal. The cost of demolishing, dismantling, tearing down or otherwise removing electric plant, including the cost of transportation and handling.

cost of service (often referred to as revenue requirements). O&M expenses, depreciation and amortization expenses, and income and other taxes found to be just and reasonable by the regulatory agency for rate making purposes plus, in the case of public utilities, an allowance for capital (usually computed by applying a rate of return to the rate base).

cost–benefit analysis. A financial model used to determine if a project will be profitable by comparing the estimated project cost with the estimated project benefit.

current asset. An asset whose useful life is less than one year, such as cash, securities and accounts receivable.

current period. The current accounting period.

debt. An instrument of finance: all debt instruments provide fixed, regular repayments to the lender by the lendee borrower, regardless of the lendee's borrower's business performance.

debt capital. Funds secured for a business by borrowing, such as through the sale of bonds.

debt expense. All expenses in connection with the issuance and initial sale of evidences of debt, such as fees for drafting mortgages and trust deeds, fees and taxes for issuing or recording evidences of debt, cost of engraving and printing bonds and certificates of indebtedness; fees paid trustees; specific costs of obtaining governmental authority; fees for legal services; fees and commissions paid underwriters, brokers and salespersons for marketing such evidences of debt; fees and expenses of listing on exchanges and other like costs.

debt, long term. Borrowed funds with a maturity (repayment date) occurring far in the future.

debt to equity ratio. The total dollar value of business debt financing divided by the total dollar value of equity financing.

decision analysis. A systematic process for making decisions and understanding risk exposure in situations of uncertainty or imperfect information which relies heavily on mathematical tools such as systems analysis and operations research.

decision support. Determination of whether a project or expenditure is a profitable endeavour to pursue. It is the process of providing risk based analysis where several options may exist.

declining balance depreciation. A depreciation method in which up to twice the straight line rate of depreciation, without considering salvage value, is applied to the remaining book value of a plant asset to arrive at the asset's annual depreciation charge.

decommissioning. The costs being accrued for the end-of-life decommissioning of the nuclear units.

decommissioning fund. For a nuclear power plant, a regular, annual set-aside of funds generated from operations, to support the eventual decommissioning of the plant when it is retired.

deferred charges. An expense that has been incurred but whose payment, for whatever reason, has been put off until some time in the future.

deferred income tax. Amounts of income tax the payment of which is delayed or put off until later years owing to accelerated depreciation or other cause.

depletion. Closely related to depreciation, this refers to the actual physical consumption of property (e.g. a coal deposit).

depreciable life. For an asset, the time period or units of activity (such as distance driven by a truck) over which depreciable cost is to be allocated. For tax returns, depreciable life may be shorter than estimated service life.

depreciation. The wearing out or loss of service value of property used in business operations.

depreciation expense. The annual allowance for the depreciation of property representing that portion which has been 'used up' during the previous twelve months.

depreciation reserve. The paper account that represents the accumulation of yearly allowances for depreciation expense. The reserve is viewed as an asset and indicates that funds are (in theory) being set aside.

derated operation. Power plant operation at less than its full rated capacity.

deregulation. The relaxation of government controls over business operations.

direct costs or expenses. Costs that are easily traced to, or associated with, a cost object, for example, costs incurred by a department for the sole benefit of the department.

direct labour. Employees directly involved in the making of a product or in the rendering of a service. This payroll falls into the category of direct costs.

direct materials. A synonym for raw materials.

disbursement. A cash amount paid out by the company.

discount rate. An interest rate, measured as a percentage, used to convert future dollars into current dollars (discounting) and vice versa (interest compounding), according to standard net present value formulas.

discounted cash flow. Analytical technique used in business to convert future cash flow estimates to their present (i.e. today's) value, using a discount rate. Related to the term net present value.

discounted cash flows. The present values of a stream of future cash flows from an investment, based on an interest rate that gives a satisfactory return on investment.

divestiture. The compulsory transfer or disposal of interests (such as stock or assets in a corporation) by government order.

earnings. Annual revenues minus annual operating expenses (including non-cash expenses such as depreciation and amortization).

earnings before interest and tax. A standard measure of business performance, calculated as annual total earnings, before deducting tax payments and payments to debt holders. Also known as net operating income.

earnings before interest, tax, depreciation and amortization. Similar to EBIT, calculated by deducting only cash expenses from revenues. Depreciation and amortization are not deducted, as in the EBIT calculation.

earnings per share. Net income available to shareholders divided by the number of shares of stock outstanding.

economic life. The time-span over which the benefits of an asset are expected to be received. The economic life of a patent, copyright, or franchise may be less than the legal or service life.

economies of scale. The principle that increased size of operations yields increased efficiency, as well as greater output.

effective tax rate. The average tax rate paid on all taxable income.

energy export tax. State taxes imposed on utilities that export energy to consumers in another state.

environmental credit. For a power plant, the right to generate a standard quantity of air emissions.

equity. Financial value of ownership or partial ownership of a company.

escapable expenses. Costs that would end with an unprofitable department's elimination.

estimated life depreciation. Depreciation determined on the basis of the estimated service life of the asset.

excise tax. Taxes imposed on the manufacture, sale, or consumption of commodities and services.

expected rate of return. The rate of return expected on an asset.

expense. The consumption of assets for the purpose of generating revenue.

extraordinary repairs. Major repairs that extend the life of a plant asset beyond the number of years originally estimated.

fair return. A legal concept of the amount of earnings to be allowed a utility company.

fair value. A legal concept of the value of a utility's property for rate making or other purposes.

FASB. The US Financial Accounting Standards Board. An independent board responsible, since 1973, for establishing generally accepted accounting principles. Its official pronouncements are entitled "Statements of Financial Accounting Standards" and "Interpretations of Financial Accounting Standards."

federal income tax. Income tax levied by the US Government on individuals and corporations.

federal unemployment tax. A tax levied by the US Government and used to pay a portion of the costs of the joint federal–state unemployment programmes.

FERC form I. A data collection instrument used by the US Federal Energy Regulatory Commission (FERC) that documents operating information from all US electric generators.

FICA tax. US Federal Insurance Contributions Act Taxes, otherwise known as social security taxes.

financial reporting. Development and issuance of required fiscal reports to meet government and other standards.

financial risk. The risk posed by the heavy use of debt support by creditors.

firm value. A company's assets less debt.

fiscal period. A financial reporting period that may cover a year (fiscal year) or a quarter (fiscal quarter).

fiscal policy. Government spending and taxation policy.

fixed asset. An asset whose useful life is greater than one year, such as a manufacturing plant, an office building, or heavy equipment.

fixed cost. A cost that remains unchanged in total amount over a wide range of production levels.

fixed expenses. Expenses that do not vary with levels of production, such as plant costs and salaries.

fixed O&M costs. O&M cost categories that are independent of the amount of energy generated by the plant.

forced outage. A power plant outage brought about when something breaks down or goes wrong (see outage).

forward price. Price of a commodity on offer today, at which a buyer can contract for delivery at some specified time in the future. For example, if the forward price of electricity for January 2008 is $75/MW·h, a buyer can contract for that price today and be assured of getting electricity at that price on 1/1/2008, regardless of what the spot price is on that day.

franchise. A grant of authority from a municipality to a public utility authorizing it to operate within the municipality's boundary.

franchise tax. A local tax imposed for the privilege of providing utility service within city limits.

functional depreciation. Loss of service usefulness or obsolescence due to technological advances or social requirements.

funded debt. Long term debt securities.

future capital requirement. An estimate of a power plant's future capital investment needs; an indicator of long term operating health and cash flow generation potential.

general and administrative expenses. The general office, accounting, personnel, and credit and collection expenses.

generation (electricity). Process of transforming other forms of energy into electrical energy, or to the amounts of electrical energy so produced, generally expressed in megawatt-hours.

government ownership. Utility or other business services that are owned and operated by a government agency (federal, state or local).

gross income. All revenues collected; the starting point for all income tax calculations.

gross profit (margin). Sales less cost of sales.

heat rate. Amount of heat (measured in BTUs) required to generate a kilowatt-hour of electricity; a measure of power plant efficiency, i.e. a lower heat rate means a more efficient plant.

historical cost. Total sum paid to purchase an asset and get it ready for use.

holding company. An organization not directly engaged in the operation of any business, but which owns the stock of other companies.

improvement. An expenditure to extend the useful life of an asset or to improve its performance (rate of output, cost) over that of the original asset. Such expenditures are capitalized as part of the asset's cost. Contrast with maintenance and repair.

inadequacy. The situation where a plant asset does not produce enough product to meet current needs.

income. Revenues received from sales and other operations of a business.

income (profit and loss) statement. A financial statement showing a company's net income — the profit after deducting all expenses — over a period. Provides investors and creditors with information that helps predict the amount, timing and uncertainty of future cash flows. Accurate predictions of future cash flows help investors assess the economic value of the company and creditors determine the probability of repayment of their claims against the company.

income from continuing operations. After tax income of the portion of the business that is continuing.

income risk. The risk of having insufficient income to carry on operations.

income tax. An annual tax levied by federal and other governments on the income of an entity. An expense. If not yet paid, a liability.

income tax rules. Rules governing how income for tax purposes and income tax are to be calculated.

incremental cost. An additional cost resulting from a particular course of action.

indirect costs. Costs of production not easily associated with the production of specific goods and services. Overhead costs. May be allocated on some arbitrary basis to specific products or departments (A&G costs).

indirect personnel (labour). Employees who are necessary for running a business but who are not directly involved in production or service. Indirect labour wages and salaries are indirect costs.

industry norms. For every industry, there is a set of normal ratios which reflect the average value for the given type of business.

inescapable expenses. Expenses that would continue even if the department were eliminated.

innovation. Process improvement using new ideas, concepts and technology.

intangible asset. A non-physical, non-current asset such as copyright, patent, trademark, goodwill, organization costs, capitalized advertising cost, computer programs, licences for any of the preceding, government licences (e.g. broadcasting or the right to sell liquor), leases, franchises, mailing lists, exploration permits, marketing quotas and other rights that give a firm an exclusive or preferred position in the marketplace.

interest. Regular payments (usually semi-annually) remitted by bond issuers to bond holders for the use of borrowed money. Annual interest payments will be equal to the face value of the bond multiplied by its coupon.

internal rate of return. Discount rate for which the present value of a company's or project's expected cash inflow equals the present value of the company's or project's cost. This rate gives a net present value of zero.

internal revenue code. Collectively, the statutes dealing with taxation that have been adopted by US Congress.

inventory. Goods owned by the corporation, in the form of raw materials, work in process, or finished goods.

investor owned utility. A utility company owned and operated by investors to serve the public.

joint cost. A single cost incurred to secure two or more essentially different products.

kilowatt-hour (kW·h). The basic unit of electrical energy equal to one thousand watts of power supplied to, or taken from, an electric circuit steadily for one hour.

liabilities. A company's obligations to pay its creditors sometime in the future.

licence renewal. The formal process undertaken by a nuclear power plant to extend the term of its operating licence.

life cycle management. The process by which nuclear power plants integrate operations, maintenance, engineering, regulatory and business activities to manage plant condition, optimize operating life and maximize plant value while maintaining plant safety.

line of sight. The ability to view how a company's corporate goals and objectives are being achieved throughout the organization.

load. The amount of energy delivered or required at any specified point or points on a system. Load originates primarily at the consuming equipment of the customers.

long lived (term) asset. An asset whose benefits are expected to be received over several years. A non-current asset usually includes investment, plant assets and intangibles.

manufacturing overhead. A synonym for factory overhead. Also termed manufacturing burden.

marginal tax rate. The rate that applies to the next dollar of income to be earned.

market price. The price at which a security or commodity is traded on the market. Electricity is traded at both the wholesale level and retail level as a commodity in a deregulated environment.

market rate of bond interest. The current bond interest rate that borrowers are willing to pay and lenders are willing to take for the use of their money.

marketable security. A security or commodity that is easily traded, such as a stock or bond or megawatt-hour contract.

matching. The principle that helps accountants determine how to record fairly a production cost as expense. Costs directly associated with producing revenue should be matched in the same period that the revenue is recorded. Costs that benefit more than one period should be matched over the periods benefited.

materiality. Concept of relative importance. An item is material if it can influence a decision made by a user of the financial statements. When an item is material, it must be accounted for within the measurement and reporting principles (generally accepted accounting principles).

merger. A combination of two or more firms in which the assets and liabilities of the selling firm are absorbed by the buying firm. Mergers are usually accomplished by the exchange of stock or the cash purchase of assets or payment of debt, or by some combination of these methods.

municipal ownership. A term applied when a business enterprise is owned and operated by a municipal government.

natural monopoly. An activity such as the provision of gas, water and electricity services characterized by economies of scale wherein the cost of service is minimized if a single enterprise is the only seller in the market.

natural resources. Forests, oil and gas wells, mineral deposits and other products of nature that have economic value. The cost of natural resources is subject to depletion. Often termed wasting assets.

net asset value. The outstanding (investment less cumulative depreciation) value of a utility asset. It is also the current price of a share of stock.

net assets. Assets minus liabilities. Net assets are equal to owner's equity.

net fixed assets. Fixed assets less accumulated depreciation.

net generation. Gross generation less power consumed for station use.

net income. Earnings or profits of an enterprise.

net loss. Negative cash flow of an enterprise.

net original cost. Original cost less accumulated depreciation.

net present value. Present (i.e. discounted) value of the cumulative future net cash flow generated by a company, plant, or project.

net present value method. Annual revenue less all expenses including tax but not book depreciation and return, discounted at an assumed rate of return (cost of money) to determine a present worth of incoming cash flow for comparison with the initial capital expenditure (an outgoing cash flow). Often used to determine a 'yes' or 'no' decision for project implementation.

net salvage. The difference between gross salvage and cost of removal resulting from the removal, abandonment or other disposition of retired plant. Positive net salvage results when gross salvage value exceeds removal costs. Negative net salvage results when removal costs exceed salvage value. Positive net salvage decreases the cost to be recovered through depreciation expense and negative net salvage increases it.

net salvage value. The salvage value of property retired less the cost of removal.

net utility plant. The investment in utility plant less depreciation.

net worth. Record of a business showing the net investment or net ownership (equity) interest in the business remaining after liability obligations are balanced against assets.

nominal rate of return. The rate of return of an investment where the purchase price and payoffs are measured in units of currency.

non-current liability. Any debt of the business that is not expected to be paid for at least one year from the date of the balance sheet.

normalization. A regulatory practice in which a utility is permitted to compute its tax liabilities or other expenditures on a periodically averaged basis rather than making actual payments for a given year, in order to gain deduction advantages earlier than would otherwise accrue, thereby resulting in tax free revenue availability not 'flowed through' to ratepayers.

nuclear asset management. A process for making resource allocation and risk management decisions at all levels of a nuclear generation business to maximize profitability and value to all stakeholders while maintaining plant safety.

O&M cost. Those expenses needed to operate and maintain a facility.

observed depreciation. Depreciation determined by physical observation and appraisal of the condition of depreciable property.

obsolescence. Depreciation caused by technological improvements.

occupational tax. A tax imposed on businesses in return for the privilege of doing business locally.

oligopoly. A market where there is very limited competition.

operating costs. Expenses incurred in a business arising from or directly related to producing the service.

operating income. Sales less cost of sales (direct costs) and operating (indirect) expenses. It excludes peripheral income, such as interest on investments, and non-operating expenses, such as tax.

operating margin. The difference between operating revenue per kilowatt-hour (i.e. market price) and operating cost per kilowatt-hour. A measure of how much cash can be generated to retire debt and cover related capital costs.

operating revenues. Income received in transacting the normal course of business.

operating risk. The probability that through operations themselves, conditions can be created that threaten the continued operation and cash flow of a business enterprise. It can include such issues as waste storage uncertainty, equipment breakdown, cooling water degradation and accidents.

opportunity cost. A sacrifice made to gain some benefit, that is, in choosing one course of action; the lost benefit associated with an alternative course of action.

option value. Increment in net present value due to the right, not the obligation, to retire a plant before expiration of the original licensed term or to operate during a licence renewal term. The option value is always positive because an option will be exercised only if future conditions are favourable.

ordinary repairs. Repairs made to keep a plant asset in its normal good operating condition.

original cost. As a measure of fair value, it is the amount of investment made to build or buy a given plant when first devoted to public service.

other direct costs. Costs, other than labour or materials, that are directly attributable to the making of the company product, e.g. factory related expenses.

other indirect costs. Expenses that cannot be attributed to the making of a specific product. Examples are depreciation of a plant in which many products are made, utility and heating expenses, or delivery fleet lease payments and maintenance costs.

outage. For a power plant, a period during which it is off-line and not producing electricity.

outage costs. Expenses solely related to a periodic refuelling outage.

out-of-pocket cost. A cost requiring a current outlay of funds.

over applied overhead. The amount by which overhead applied on the basis of a predetermined overhead application rate exceeds overhead actually incurred.

overhead. The costs associated with support from non-electricity producing organizations.

owner's equity. The ownership interest in a business enterprise.

parent company. A company that owns the stock of one or more subsidiaries and may be either a holding company or hybrid company.

payback period. Annual revenue less all expenses including tax (but not book depreciation or return) divided into the initial capital expenditure to determine the number of years required to equal or pay back the initial capital expenditure.

payroll tax. A tax levied on the amount of payroll or on the amount of an employee's gross pay.

performance measurement. The process of measuring results against the desired state.

phantom tax. A regulatory issue arising from the use of accelerated depreciation methods, which reduces taxable income and makes more capital available for construction.

physical depreciation. Loss of service usefulness or life due to wear and tear from use or other causes, such as rust or rot.

planned outage. The period during which a power plant it is taken off-line to perform refuelling and planned maintenance (see outage).

plant. Plant assets.

plant assets. Buildings, machinery, equipment, land and natural resources. The phrase 'property, plant and equipment' is, therefore, a redundancy. In this context, 'plant' means buildings.

plant phase-in. The gradual inclusion of a new plant in rate base over a period of time to avoid sudden large rate increases.

power pool. A regional organization of electricity companies interconnected for the sharing of reserve generating capacity and power production coordination.

predetermined overhead application rate. A rate that is used to charge overhead cost to production, calculated by relating estimated overhead cost for a period to another variable such as estimated direct labour cost.

present value. The discounted value of future cash flows.

pre-tax earnings. Earnings left after addition of operating income to non-operating income (e.g. interest earned on loads) followed by deduction of non-operating expenses such as extraordinary costs, but not tax.

price cap regulation. A rate setting process whereby a ceiling is placed on the price of service instead of limiting the allowable rate or return.

price earnings ratio. The market common stock price divided by the annual earnings per share of common stock. The market price used may be a spot price, or an average closing price or the high and low prices for a period and the earnings for the corresponding period.

prior period. A preceding accounting period.

pro forma statement. Financial statement prepared on the basis of some assumed future event. It usually consists of an income statement, balance sheets and cash flow statement.

production cost. Costs assigned directly to the production of electricity. Electricity generation production cost equals O&M cost plus fuel expense. It is normally expressed in cents per kilowatt-hour.

production expense. An expense incurred in the operation of a plant.

production method. A depreciable asset is given a depreciable life measured, not in elapsed time, but in units of output or perhaps in units of time of actual use. Then, the depreciation charge for the period is a portion of the depreciable cost equal to the actual output produced during the period divided by the expected total output to be produced over the life of the asset. Sometimes referred to as the units of production (or output) method.

productivity. The amount of output generated per unit of input. In a power plant, capacity factor (i.e. megawatt-hours generated per unit of megawatt capacity) is a measure of productivity.

profit. Income remaining after business expenses are paid.

profit margin. The difference between revenue per kilowatt-hour (market price) and total cost per kilowatt-hour (includes operating costs, debt payments, tax and other corporate costs). A measure of cash generated for stockholders.

prudent investment. A measure of fair value: a reasonable investment that should be invested in a given plant.

public ownership. See government ownership.

public service (utilities) commission. State regulatory body governing the rates and practices of utilities.

public utility. A business enterprise rendering a service considered essential to the public and, as such, subject to regulation in the public interest, usually by statutory law.

public utility district. Political subdivisions that are independent of local or federal government and which are voted into existence by residents for the specific purpose of rendering a utility service.

rate base. Value of property upon which a utility is given the opportunity to earn a specified rate of return as established by a regulatory authority.

rate case. A proceeding, usually before a regulatory commission, involving the rates to be charged for a public utility service.

rate of return. The return earned or allowed to be earned by a utility enterprise calculated as a percentage of its fair value or rate base.

rate of return on average investment. The annual after tax income from the sale of an asset's product divided by the investment in the asset.

rate of return on common stockholder's equity. Net income after tax and dividends on preferred stock divided by average common stockholder's equity.

rate of return on total assets employed. Net income after tax, plus interest expense, expressed as a percentage of total assets employed during the period.

ratio. A numerical relationship that compares one magnitude with another in the form of a multiple, such as 2:1. The multiple may also be expressed as a fraction (2/1), percentage (200%), or rate (2 per 1).

receipt. A cash amount received by the company.

recovery property. Property eligible for write-off under the accelerated cost recovery system.

regulation. A process whereby governmental powers are used to direct or control some phase or unit of economic activity.

regulatory agency. A government body that regulates enterprises in certain specified industries.

regulatory assets and liabilities. Assets and liabilities that result from the rate actions of regulatory agencies.

regulatory compliance. Power plant operation within the scope of regulatory rules.

remaining life. Under this method of determining depreciation allowance, when the estimated useful life is revised, the annual depreciation rate is re-determined for future years. Also, the remaining design or licence life of an electricity generating facility.

replacing or **replacement.** The construction or installation of electric plant in place of property retired, together with the removal of the property retired.

reproduction cost. As a measure of fair value. This is the amount which would be required to build a given plant today.

reserve. Amounts recorded in accounting records as earmarked or credited for certain purposes, but not necessarily physically segregated in special accounts. Thus, a reserve for depreciation or a reserve for contingencies may be simply bookkeeping records for such a fund.

reserve theory of depreciation. Presumes replacement of assets through the establishment of a separate fund, which will be sufficient to cover replacement costs when the old asset is retired.

retained earnings. The dollar amount of assets furnished by the earnings of the company that were not distributed as dividends.

retirement theory of depreciation. Presumes gradual retirement of an asset at a given cost.

return. Represents the money required annually to compensate security holders for the funds provided as invested capital for the plant facilities. It consists of interest on debt, dividends on preferred stock and earnings on common equity. The return element is variable, being greatest initially and then declining over the years because a fixed cost of money, or rate of return, is applied annually to the net plant (total plant less accumulated depreciation). To adjust for the variability of this component, present worth techniques are employed to obtain an equivalent, constant, annual return.

return allowance. The rate of return designated by a regulatory commission for testing the reasonableness of rates.

return on assets. Earnings as a percentage of total assets. The ratio of net income to total assets.

return on equity. Earnings as a percentage of stockholder equity. The ratio of net income to common equity. It measures the rate of return on common stockholders' investment. The profit earned for each dollar of shareholders' equity.

return on investment. Annual revenue less all expenses, including tax and book depreciation but not return, divided by investment required.

return on net assets. The profit earned on each dollar invested in assets.

revenue. Receipts from the sale of goods and services.

revenue bond. A bond upon which the company promised to pay interest only if earned, sometimes called an income bond.

revenue recognition. Revenue is reported in the fiscal period in which the sale is made (or the service is provided), regardless of whether cash is collected from the customer or the customer still owes for the merchandise (service).

revenue requirement. The amount a utility must collect to pay expenses and provide a fair return to investors.

revenue tax. Tax imposed on business gross receipts or otherwise based on revenue, sometimes in place of, or in addition to, property tax.

risk. The measure of the variability of the return on investment. For a given amount of return, most people prefer less risk to more risk. Therefore, in rational markets, investments with more risk usually promise, or are expected to yield, a higher rate of return than investments with lower risk. Most people use 'risk' and 'uncertainty' interchangeably. In technical language, however, these terms have different meanings. 'Risk' is used when the probabilities attached to the various outcomes are known, such as the probabilities of heads or tails in the flip of a fair coin. 'Uncertainty' refers to an event where the probabilities of the outcome, such as winning or losing a lawsuit, can only be estimated.

risk premium. Extra compensation paid to an employee or extra interest paid to a lender, over amounts usually considered to be normal, in return for their undertaking to engage in activities that carry more risk than normal.

salvage value. The estimated dollar amount that would be received upon a sale of property after that property has become worn out or unproductive.

scrap value. Salvage value assuming item is to be scrapped. Residual value.

self-assessment. A periodic review conducted by the site or company to compare overall results with expected results. Sources of information included in a self-assessment may be management comments, employee interviews, reviews of plant events and trends, external assessments of other companies, independent assessments and benchmarking. The goal of self-assessment is to evaluate the current direction of the business with regard to nuclear safety, shareholder value and corporate stewardship.

semi-variable cost. A cost that changes with production volume but not in the same proportion.

service area. The territory in which a utility company has the right to supply or make available its utility service.

service departments. Departments that do not produce revenue but which supply other departments with essential services.

service life. The period of time a plant asset is used in the production and sale of other assets or services.

service life depreciation. Depreciation determined on the basis of estimated service of the asset.

service obligation. A term used to mean the obligations, which are among the duties a public utility has to fulfil. They are usually considered to include the duty to serve all, to provide adequate service, and to render safe, efficient and non-discriminatory service.

service value. The difference between original cost and net salvage value of electrical plant.

short term debt. Bank borrowings or bonds with less than the traditional 20–30 year maturities.

sinking fund method of depreciation. The periodic charge is an amount such that when the charges are considered to be an annuity, the value of the annuity at the end of depreciable life is equal to the acquisition cost of the asset. In theory, the charge for a period should also include interest on the accumulated depreciation at the start of the period. A fund of cash is not necessarily, or even usually, accumulated. This method is rarely used.

spot market. Commodity transactions whereby participants make buy and sell commitments of relatively short duration, in contrast to the contract market in which transactions are long term.

spot price. Price of a commodity for immediate exchange at a specific point in time.

state unemployment tax. A payroll tax levied by a state, the proceeds from which are used to pay benefits to unemployed workers.

statement of cash flows. Statement that reports all the changes that have occurred in the balance sheet during the fiscal period, either providing or using cash.

station use (generating). The kilowatt-hours used internally at an electricity generating station for purposes other than sale. Station use includes electrical energy supplied from house generators, main generators, the transmission system and any other sources. The quantity of energy used is the difference between the gross generation plus any supply from outside the station and the net output of the station.

straight line depreciation. A depreciation method that allocates an equal share of the total estimated amount a plant asset will be depreciated during its service life to each accounting period in that life.

stranded cost recovery. Ability of an electric utility to recover stranded costs through surcharges or other means, as allowed by a regulatory authority.

stranded costs. Costs incurred in the past that have been rendered non-economic and/or 'stranded' due to the onset of competition or by other changing economic or business conditions.

stranded investment. Net plant investment held by owners of a facility at the time when deregulation (restructuring) takes place. 'Stranded' implies an inability to recover the investment over the original amortization period.

strategy and planning. Strategy identifies future business direction and goals. The key objectives in strategy are to employ company strengths to take advantage of business opportunities, while avoiding business threats created by company weaknesses. Planning refers to business planning or the objectives and methods anticipated to implement the strategies.

sum-of-the-year's-digits depreciation. A depreciation method that allocates depreciation to each year in a plant asset's life on a fractional basis. The denominator of the fractions used is the sum-of-the-year's-digits in the estimated service life of the asset and the numerators are the years' digits in reverse order.

sunk costs. Costs incurred (i.e. funds spent or committed) in the past that cannot be affected by any present or future course of action.

tax avoidance. A legal means of preventing a tax liability from coming into existence.

tax credit. A direct, dollar for dollar, reduction in the amount of tax liability.

tax. A non-penal, but compulsory, charge levied by a government on income, consumption, wealth, or other bases for the benefit of all those governed. The term does not include fines or specific charges for benefits accruing only to those paying the charges, such as licences, permits, special assessments, admission fees and tolls.

technical leverage. Using the relationship available among various informational tools (Intranet, MS Access, etc.) to gain and/or communicate valuable insights into a business.

test period. Also referred to as test year, this is an historic period of time selected and used as a proxy for the future in the electricity rate setting process.

thermal performance. The amount of fuel energy converted into thermal (heat) energy (which is subsequently converted into electrical energy).

total sales. Total sales less allowances for returns and bad debt. Same as sales.

transaction cost. Cost associated with buying or selling assets.

unbundling of rates. A pricing structure which charges separately for the individual components of providing various utility services.

uncontrollable cost. A cost the amount of which a specific manager cannot control within a given period of time.

under applied overhead. The amount by which actual overhead incurred exceeds the overhead applied to production, based on a predetermined application rate and evidenced by a debit balance in the overhead account.

uniform system of accounts. A system of accounts prescribed by The US Federal Energy Regulatory Commission for use by the utility companies under its jurisdiction.

unit capability factor. Ratio of available energy generation (energy that could have been produced considering only limitations under plant management control) to reference energy generation.

units of production depreciation. A depreciation method that allocates depreciation to a plant asset based on the units of product produced by the asset during a given period to the total units the asset is expected to produce during its entire life.

unplanned capability loss factor. For a nuclear power plant, total off-line time annually caused by factors not under the plant operator's control.

used and useful rule. A principle of electric utility financial regulation in which a utility is entitled to earn a return on all its property used and useful to consumers in the provision of utility service.

useful life. The period of time over which property is depreciated. The length of time that property or equipment is expected to last before replacement.

utility plant accounts. The accounts in which the records of investment in plant and equipment are kept.

valuation. A process by which the value of an asset or resource is assessed.

variable costs. Those expenses of a business enterprise that vary with changes in volume of output, such as outlays for fuel to generate electrical power.

variable expenses. Expenses that fluctuate with the level of production.

variable O&M costs. O&M cost categories that depend at least partially on the amount of energy generated by the plant, excluding fixed costs that are incurred regardless of whether the resource is operating.

watt. The electrical unit of power or rate of doing work. The rate of energy transfer equivalent to one ampere flowing under a pressure of one volt at unity power factor. It is analogous to horsepower or foot-pounds per minute of mechanical power. One horsepower is equivalent to approximately 746 watts. One thousand watts delivered for one hour equals one kilowatt-hour. Similarly, one million watts delivered for one hour equals one megawatt-hour.

weighted average cost of capital. A weighted average of the component costs of debt, preferred stock and common equity. Also called the composite cost of capital.

windfall profits tax. A tax designed to limit corporate profits following a sudden increase in prices.

working capital. The amount of cash or other liquid assets that a company must have on hand to meet the current cost of operations until such a time as its customers reimburse it. Sometimes it is used in the narrow sense to mean the difference between current and accrued assets and current and accrued liabilities.

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This report has been prepared for the benefit of nuclear plant managers and operators. Its primary purpose is to identify and define a number of economic performance measures for use at nuclear power plants operating in deregulated, competitive electricity markets. In addressing the value of economic measures, the report presents and discusses a general definition and classifications of nuclear economic indicators within the context of regulation, competition and the economic requirements for constructing, operating and decommissioning nuclear plants.

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