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Reliability Modelling and Assessment of Power System Operation in the Competitive Electric Energy Market

This Chapter describes the main concepts and features of appropriate computational methodologies that have been developed for assessing the overall reliability and operational performance of electric power systems operating under the framework of the competitive electric energy market. These methodologies are based on the Monte - Carlo sequential simulation approach and are used for conducting the appropriate assessment studies on the composite generation and transmission power systems. A special attention is given to the impact of renewable energy sources while appropriate case studies are presented and examined thoroughly in order to describe more effectively the basic features of the developed methodologies.

6.1 Introduction

In recent years, electric power systems are adopting new technologies in their structure in order to achieve better performance and efficiency in the electricity production, transmission and distribution [1]. One of the most important aspects of the competitive electric energy market is the operation of independent power producers that can be connected at any system voltage level. This fact together with additional financial incentives being developed in many countries has increased considerably the number of power generating units using renewable energy sources [2].

Additionally, the role of transmission networks receives a great attention under the framework of this new environment being applied. Their role is to enable the competition by allowing an open access of all participants while keeping the system reliability and operational performance within appropriate standards [1,2].

An increased need for simulating the operation of power systems has emerged in order to take into consideration all the special operating features and procedures that are being incorporated as a result of this new environment. For this purpose, appropriate computational methods are being developed to be used for examining alternative operational schemes of power systems and investigating the impact of certain features (such as the penetration level of renewable energy sources) to their overall reliability and operational performance. These methods are mainly based on the Monte - Carlo sequential simulation approach and it was proved that they are very useful for comparing thoroughly different planning and operational schemes of power systems in order to deduce the optimal one.

6.2 Monte–Carlo Sequential Simulation Approach

The Monte – Carlo sequential simulation approach is a stochastic simulation procedure and can be used for calculating the operational and reliability indices of a power system by simulating its actual behavior [3–6]. The problem is treated as a series of real experiments conducted in simulated time steps of one hour. A series of system scenarios is obtained by hourly random drawings on the status of each system component and the determination of the hourly load demand. The operational and reliability indices are calculated for each hour with the process repeated for the remaining hours in the year (8760 hours). The annual reliability indices are calculated from the year's accumulation of data generated by the simulation process. The year continues to be simulated with new sets of random events until obtaining statistical convergence of the indices. The sequential simulation approach steps through time chronologically, by recognising that the status of a system component is not independent of its status in adjacent hours. Any event occurring within a particular time step is considered to occur at the end of the time step and the system state and statistical counters are updated accordingly. This approach can model any issues of concern that involve time correlations and can be used to calculate frequency and duration reliability indices. One very important advantage of the sequential simulation is the simplification of a particular system state simulation by considering information obtained from the analysis of the previous system states. This can only be applied when the system states change very little from one time step to the next. Such an assumption can be made for the transmission system that does not suffer large changes very often.

An efficient computational methodology has been developed at the National Technical University of Athens (NTUA) for the operational and reliability assessment of power systems applying the above principles of the Monte – Carlo sequential simulation approach. This methodology has the following main features [6]:

- The random events are determined by using appropriate pseudo-random numbers that are generated applying the mixed multiplicative congruent method. The antithetic sampling technique is also used for variance reduction.
- The classical two-state Markovian model is generally used to represent the operation of the system generating units. The generating units of certain thermal plants (for example, combined cycle plants) or the large thermal units may be represented by a multiple state model in order to recognise their derated states.
- The generating units may be taken out for scheduled maintenance during certain time periods of the year by using their appropriate data being specified.

The prime objective of the above computational methodology is to calculate appropriate indices that quantify the operational and reliability performance of a power system. It is generally considered that the following indices are the most important system and load-point indices while they have the corresponding units and acronyms in parentheses:

- Loss Of Load Expectation (LOLE) in hours/year.
- Loss Of Energy Expectation (LOEE) in MWh/year.
- Frequency of Loss Of Load (FLOL) in occurrences/year.
- Expected Demand Not Supplied (EDNS) in MW.
- Average Duration of Loss of Load (ADLL) in hours.

6.3 Reliability Modelling and Operational Performance of Isolated Power Systems with an Increased Penetration of Renewable Energy Sources

6.3.1 General

An important aspect of power generation systems operating under the framework of the competitive electric energy market is the increased use of renewable energy sources. However, their integration into the existing and future power systems represents an enormous technological challenge since there are serious limitations to the use of renewable energy sources due to the uncertainty of the weather conditions that constitute the main features of their operation. For this purpose, during the recent years, additional research effort has been devoted concerning the impact of the respective generating units on the operational performance of these systems. Wind has proven to be the most successful of all available renewable sources, since it offers relatively high capacities with generation costs that are becoming competitive with conventional energy sources. However, a major problem to its effective use as a power source is the fact that it is both intermittent and diffuse as wind speed is highly variable and site specific [7]. Additionally, an increased use of small hydroelectric plants that operate continuously throughout a year has also been identified.

The isolated power systems face specific problems that are related to their planning and operation when they are compared with the interconnected systems. In general, the customers of these systems face higher costs and poorer quality of supply than the customers of large interconnected systems. The main problems being identified concern the security and reliability of the systems while additional difficulties are expected due to high wind power penetration. Therefore, the introduction of high wind power penetration in the generation system of isolated power systems may reduce their operational reliability and dynamic security. A common aspect to all these problems is the requirement to ensure that sufficient reserve capacity exists within the system to compensate for sudden loss of generation. It is therefore evident that generation planning and operation is very critical on isolated systems.

6.3.2 General Features of Isolated Power System Operation

The reliability and operational assessment studies of isolated power systems require appropriate modeling of their features that affect their operation. These basic features are the following:

- The generation system mainly consists of thermal generating units of various types while hydroelectric power plants may exist that consist of appropriate generating units and reservoirs. Additionally, wind parks may be connected to the system busbars and they consist of appropriate units.
- The existing steam turbines and the internal combustion engines mainly supply the base-load demand. The combustion turbines have high production cost and they normally supply the daily peak load demand or the load demand that cannot be supplied by the other system units in outage conditions.
- The thermal generating units are called on to operate in order to supply the relevant load demand of the system according to a priority order that is determined by their production cost. Additionally, a level of spinning reserve capacity must be available

for use in emergency conditions that is usually determined by using an appropriate deterministic security criterion. It can be equal to either a certain percentage of the system load demand (e.g. 10%) or the capacity of the largest unit in operation or a constant value.

- A hydro chain may exist that consists of hydroelectric plants being located on the same river or water flow. The respective topographical sites or the construction facilities mainly determine the storage capability of reservoirs. Pump storage facilities may also exist.
- A variety of operating and water management policies can be implemented and they have a significant impact on the reliability and operational performance of the systems that have limitations in the energy being produced by the hydroelectric power plants.
- Several factors affecting the actual dispatch of generating units must be considered such as fuel costs, energy states of reservoirs, restrictions in use of water, energy used to pump water and irrigation requirements.
- Isolated power systems with a large wind penetration margin might face large voltage and frequency excursions and dynamically unstable situations when fast wind power changes and very high wind speeds result in sudden loss of wind power generation. This loss can be compensated with additional production from the system conventional generating units that are in a spinning reserve mode of operation. These system operational features determine the wind penetration margin that is expressed as a fraction of the wind power generation to the respective load demand. This penetration margin can be increased by considering the operation of hydroelectric plants that incorporate pumping facilities.

6.3.3 Computational Methodology

An efficient computational methodology has been developed at NTUA for the reliability and cost assessment of isolated power systems. This methodology integrates the operating aspects of wind parks and small hydroelectric power plants and evaluates their impact on the reliability and production cost of the system. These aspects are the following:

- The system conventional generating units are divided into two groups (fast, slow) according to their technical characteristics to change their power output. Additionally, these units are divided into two groups that can either supply the base-load demand or not supply it respectively.
- A number of wind parks can be installed at various geographical sites and each wind park consists of a certain number of groups of identical wind generating units. These wind parks are connected to the appropriate system busbars applying the existing connection rules of the system.
- The hourly wind speed of a geographical site is represented by an appropriate normal distribution which means that the values of the mean and standard deviation need to be given as input data for each hour of the year (8760 points). For simplicity reasons, the standard deviation may be assumed constant (e.g. 5%). The available power output of a wind-generating unit at any time point is calculated by using either a linear or nonlinear relationship between the power output and the wind speed of the respective geographical site.

- The classical two-state Markovian model simulates the operation of wind generating units.
- The total wind power generation of the system at any simulation time period of the year is not allowed to exceed a certain fraction of the respective system load demand. This fraction expresses the wind penetration constraint (margin) being assumed in order to retain acceptable service reliability, security and efficient operation of the conventional generating units. If the total wind power generation of the system is higher than the limiting value, it is necessary to reduce this generation level. For this purpose, the system control center will send appropriate orders to each wind park to reduce its total power output by a certain amount. This amount of power output is calculated so that the same percentage reduction will be applied for each wind park being in operation. As a result, it is assumed that a certain number of wind generating units in each wind park will be either disconnected from the system or decrease their power output by using appropriate procedures that take into account the technical characteristics of the respective units.
- A number of small hydroelectric power plants can be connected at appropriate system busbars and each plant consists of a certain number of identical generating units. It is considered that these units operate continuously throughout the year and their hourly power output is calculated by taking into account the respective monthly production and a typical curve for the hourly production of one day.
- The operational performance of wind and hydroelectric generating units is quantified by taking into account the events which occur when they fail to produce their available output capacity due to their existing limitations (failure, maintenance).
- The available spinning reserve of the system for each simulation time period is calculated by taking into account the operational features of system generation during the previous time period. For this purpose, two criteria are used. Criterion 1 assumes that the spinning reserve is equal to a certain percentage of the total wind power generation in order to compensate a sudden loss of this generation output in the cases of very fast wind speed changes. Criterion 2 assumes that the spinning reserve is equal to a certain percentage of total system loads in order to compensate for a sudden loss of the generation provided by the system conventional generating units (reliability criterion). The actual value for the spinning reserve is calculated as the greatest value being obtained by the two criteria. For this purpose, only the fast conventional generating units are taken into account.

An appropriate algorithm was developed and incorporated in the above methodology in order to simulate the dispatch procedures of system generating units for supplying the respective load demand in each simulation time period. This algorithm takes into account only the generating units of the system that are available (not being either in a repair or maintenance state) and has the following basic steps:

1. The small hydroelectric generating units are called on to operate and their power output is calculated according to their technical characteristics.
2. The conventional generating units, that are assigned to supply the base-load demand, are called on to operate at their minimum output capacity according to their priority order.

3. The power output of wind generating units is calculated by using the relevant wind speed data in each geographic site.
4. The wind penetration level is taken into account and, if it is necessary, appropriate reduction orders are applied to the power output of wind generating units.
5. The remaining load demand to be supplied is allocated to the conventional generating units. Firstly, the units supplying the base-load demand are called on to operate with the appropriate power output by using their priority order. If additional power generation is required, the other available conventional generating units are called on to operate by using their priority order.

It must be noted that the criteria for the system spinning reserve are also taken into account. These criteria determine the power output of the conventional generating units and the operation of additional units if it is required.

Using the developed computational methodology, the following additional system indices are calculated which have the corresponding units and acronyms in parentheses:

- a) Four indices quantifying the system generation capability and production cost:
 - Expected total energy supplied by conventional generating units (EGSM) in GWh/year.
 - Expected energy supplied by wind generating units (EWSM) in GWh/year.
 - Expected energy supplied by small hydroelectric power plants (EHSM) in GWh/year.
 - Expected production cost of the generation system (PCSM) in Euro/MWh.
- b) Four indices quantifying the operational performance of wind generating units by taking into account the events that may occur (failures, maintenance):
 - Frequency of events being occurred (FNSWS) in occurrences/year.
 - Expected annual duration of events being occurred (DNSWS) in hours/year.
 - Expected load demand not supplied during the events being occurred (PNSWS) in MW.
 - Expected energy not supplied during the events being occurred (ENSWS, ENSWM) in MWh/year.
- c) Three indices quantifying the operational performance of the wind generation system by taking into account the events that occur when an order is issued for wind power reduction:
 - Frequency of such events (AVPRF) in hours/year.
 - Expected energy not supplied (AVPRE) in MWh/year.
 - Expected wind power output not produced (AVPRL) in MW.
- d) Four indices quantifying the operational performance of the small hydroelectric generating units by taking into account the events that may occur (failures, maintenance):
 - Frequency of events being occurred (FNSHS) in occurrences/year.
 - Expected annual duration of events being occurred (DNSHS) in hours/year.
 - Expected load demand not supplied during the events being occurred (PNSHS) in MW.
 - Expected energy not supplied during the events being occurred (ENSHS, ENSHM) in MWh/year.

- e) Three indices quantifying the available spinning reserve by applying the respective criterion:
- Available spinning reserve (AVSPRES) as a percentage of the respective load demand.
 - Percentages of applying Criteria 1 and 2 for evaluating spinning reserve (FWIND, FLOAD).

6.3.4 Assessment Studies

The developed computational methodology was applied for conducting reliability assessment studies on a typical isolated power system that is based on the power system of a Greek island. The main features of the system are the following:

- The installed generating capacity of the conventional units is equal to 522.6 MW. The system peak load demand is equal to 430 MW and occurs on a winter day while the overnight loads are approximately equal to 25% of the corresponding daily peak load demands.
- There are twenty conventional generating units of four different types that are installed in two power plants (I and II). These plants are located near to the major load points of the island for various reasons such as electrical design, environmental issues, etc. The complete characteristics of the generating units are shown in Table 6.1.
- There are six wind parks being installed at five different geographic sites of the island with 131 generating units having various power output capacities and their total generating capacity is equal to 66.85MW. The wind parks are usually installed in geographic sites with favorable wind conditions and their major characteristics are shown in Table 6.2.
- There are eight small hydroelectric power plants with eight generating units having various power output capacities and their total installed capacity is equal to 10.05 MW. The main characteristics of these units are shown in Table 6.3.
- The power generation system is only considered since it is assumed that the transmission network of the isolated system is fully reliable with an unlimited transmission capacity during any outages.
- The prices used for the calculation of the production cost for the generation system are only the supply prices of fuel.
- The available spinning reserve is calculated assuming that reserves are either equal to 100% of total wind power generation according to Criterion 1 or they are equal to 10% of the system load demand according to Criterion 2.
- The typical curve for the hourly production of hydroelectric plants for one day is a constant straight line.

This system provides a good example for illustrating the different operating features of isolated power systems. The full set of system indices was evaluated for the following eight alternative case studies:

Case 1: Base case study assuming a wind penetration margin of 20%.

Case 2: As in Case 1 but the wind penetration margin is decreased to 10%.

- Case 3:** As in Case 1 but the number of system wind generating units increases to 200 and their installed power output capacity increases by 35MW (52.3%). The respective data are shown in Table 6.4.
- Case 4:** As in Case 3 but the load demand increases by 8% (34.4 MW).
- Case 5:** As in Case 1 but the typical curve for the hourly production of hydroelectric plants for one day shows a greater power output during the daily peak load demand hours.
- Case 6:** As in Case 1 but the typical curve for the hourly production of hydroelectric plants for one day shows a greater power output during the daily base-load demand hours.
- Case 7:** As in Case 1 but the number of system small hydroelectric generating units increases to 16 and their installed power output capacity increases by 100% (10.05MW). The respective data are shown in Table 6.5.
- Case 8:** As in Case 1 but no small hydroelectric power plants exist.

Unit No.	Plant No.	Type (*)	Load Pick-up	Priority Order	Output Capacity (MW)		Maintenance Duration (days)
					Max	Min	
G1	II	T	Fast	12	13.0	0.0	28
G2	II	T	Fast	8	16.0	0.0	28
G3	II	T	Fast	10	19.0	0.0	28
G4	II	C	Fast	5	125.0	24.0	28
G5	I	S	Slow	1	23.5	14.0	35
G6	I	S	Slow	1	23.5	14.0	35
G7	I	S	Slow	1	23.5	13.0	35
G8	I	T	Fast	6	40.0	10.0	28
G9	I	D	Fast	4	11.5	0.0	42
G10	I	D	Fast	4	11.5	0.0	42
G11	I	D	Fast	4	11.5	0.0	42
G12	I	D	Fast	4	11.5	0.0	42
G13	I	T	Fast	9	15.0	0.0	28
G14	I	T	Fast	9	15.0	0.0	28
G15	I	T	Fast	11	15.0	0.0	28
G16	I	S	Slow	3	5.9	3.9	28
G17	I	S	Slow	2	14.1	7.0	28
G18	I	S	Slow	2	14.1	7.0	28
G19	II	T	Fast	7	57.0	0.0	28
G20	II	T	Fast	7	57.0	0.0	28
(*) T: Combustion Turbine. S: Steam Turbine C: Combined Cycle Engine D: Diesel Engine							

Table 6.1. Data for the Conventional Generating Units of the System

Wind Park No.	Group No.	Geographic Site	Number of Units	Output Capacity of Units (MW)	Installed Power Capacity (MW)
1	1	1	17	0.30	5.10
	2	1	3	0.50	1.50
2	3	3	17	0.60	10.20
3	4	3	17	0.60	10.20
4	5	2	50	0.50	25.00
5	6	4	18	0.55	9.90
6	7	5	9	0.55	4.95
Total	7		131		66.85

Table 6.2. Data of System Wind Generating Units

Power Plant No.	Number of Units	Output Capacity of Units (MW)	Installed Power Capacity (MW)	Annual Energy Produced (GWh)
1	1	0.75	0.75	3.304
2	1	1.00	1.00	4.405
3	1	0.55	0.55	2.467
4	1	2.00	2.00	8.810
5	1	1.30	1.30	5.726
6	1	2.85	2.85	12.423
7	1	0.60	0.60	2.643
8	1	1.00	1.00	4.405
Total	8		10.05	44.183

Table 6.3. Data of System Small Hydroelectric Plants

Wind Park No.	Group No.	Geographic Site	Number of Units	Output Capacity of Units (MW)	Installed Power Capacity (MW)
1	1	1	27	0.30	8.10
	2	1	5	0.50	2.50
2	3	3	26	0.60	15.60
3	4	3	26	0.60	15.60
4	5	2	75	0.50	37.50
5	6	4	27	0.55	14.85
6	7	5	14	0.55	7.70
Total	7		200		101.85

Table 6.4. Data of System Wind Generating Units (Cases 3 and 4)

Power Plant No.	Number of Units	Output Capacity of Units (MW)	Installed Power Capacity (MW)	Annual Energy Produced (GWh)
1	2	0.75	1.50	6.608
2	2	1.00	2.00	8.810
3	2	0.55	1.10	4.934
4	2	2.00	4.00	17.620
5	2	1.30	2.60	11.452
6	2	2.85	5.70	24.846
7	2	0.60	1.20	5.286
8	2	1.00	2.00	8.810
Total	16		20.10	88.366

Table 6.5. Data of System Small Hydroelectric Plants (Case 7)

The results being obtained for the above eight Case studies are presented in Table 6.6. A considerable number of comments can be drawn from these results but the most important ones are the following:

- The decrease of wind penetration margin decreases the wind generation system indices and also decreases the system reliability performance. Comparing the results of the respective indices for Cases 1 and 2 demonstrates this.
- The increase of wind penetration margin and the addition of wind generating units always improve the system reliability indices as there is more available power to supply the load demand. Furthermore, the energy supplied by wind generating units is increased while the energy supplied by the conventional units of the system is decreased. However, the system production cost increases as indicated by the respective results for Cases 1, 3, 7 and 8.
- The addition of small hydroelectric units improves the system reliability indices, as there is more available power to supply the load demand, and increases the system hydroelectric generation indices as it can be seen by comparing the results of Cases 1 and 7. Furthermore, the total energy being supplied by both the wind generating units and conventional units decreases.
- When the power output of hydroelectric generating units is greater during the time periods of the daily peak load demands (Case 5), the LOEE index is smaller compared with that for Case 6, where their power output is greater during base load demand hours.
- The percentages of criteria 1 and 2 for the calculation of the available spinning reserve of the system (FWIND) vary according to the power output capacity of wind generating units and the wind penetration margin. When an increased level of system wind penetration margin is assumed (Case 1) or the installed power output capacity of system wind generating units is assumed to increase (Case 3), criterion 1 mainly determines the available spinning reserve. However, when the wind penetration margin is decreased (Case 2), criterion 2 mainly contributes to the evaluation of spinning reserve.

Case Study Index	1	2	3	4	5	6	7	8
LOLE	5.105	6.000	2.945	6.87	5.160	5.115	4.355	6.120
LOEE	142.24	164.05	72.738	196.48	141.32	143.57	116.79	172.94
EDNS	10.251	10.490	6.115	13.771	10.191	10.328	8.902	11.584
FLOL	2.200	2.365	1.430	2.955	2.195	2.205	1.920	2.480
EGSM	1766.04	1863.72	1683.40	1829.42	1765.57	1766.55	1726.44	1806.28
EWSM	300.535	202.834	383.247	401.918	301.007	300.022	296.909	303.423
EHSM	43.152	43.152	43.152	43.152	43.154	43.154	86.403	-
PCSM	101.73	99.265	103.43	100.17	101.71	101.73	102.72	100.77
FNSWS	1.975	1.975	1.215	1.215	1.975	1.975	2.635	1.975
DNSWS	8731.55	8731.55	8749.09	8749.09	8731.55	8731.55	8731.55	8731.55
PNSWS	1.5056	1.0183	2.0269	2.1252	1.5080	1.5030	1.5087	1.5206
ENSW	15.84	10.773	20.353	21.325	15.866	15.815	15.657	15.988
ENSWM	9.795	7.832	13.574	13.939	9.805	9.785	9.736	9.839
AVPRF	2503.0	7965.9	6077.2	5328.06	2501.4	2504.0	2672.2	2339.5
AVPRE	24.267	121.967	113.291	94.620	23.795	24.780	27.893	21.380
AVPRL	9.6951	15.3111	18.6419	17.7588	9.5128	9.8960	10.4382	9.1385
AVSPRES	14.73	10.01	18.55	18.03	14.75	14.70	14.85	14.58
FWIND	90.9	46.9	99.34	98.87	90.9	90.88	91.4	90.2
FLOAD	9.1	53.1	0.66	1.13	9.1	9.12	8.6	9.8
FNSHS	31.365	31.365	31.365	31.365	31.365	31.365	58.230	-
DNSHS	663.65	663.65	663.65	663.65	663.65	663.65	1287.17	-
PNSHS	0.648	0.648	0.648	0.648	0.648	0.647	0.669	-
ENSHS	0.436	0.436	0.436	0.436	0.436	0.436	0.885	-
ENSHM	1.022	1.022	1.022	1.022	1.022	1.022	1.874	-

Table 6.6. System Reliability and Operational Indices

6.4 Reliability and Cost Assessment of Power Transmission Networks in the Competitive Electric Energy Market

6.4.1 General

Power transmission systems are increasingly involved in the competitive electric energy market and their role becomes more important since it must enable the open access of several players even though in a regulated way. For this purpose, certain strategies must be developed to insure that the system will be able to optionally utilize its total facilities since it will experience an increase in the number of energy sales and purchases. This increase is due to a number of reasons and includes a growing number of wheeling transactions between investor-owned utilities, cogeneration facilities and industrial consumers [8]. Present day practice on wheeling is that consumers and suppliers make direct commercial contracts across wholly third party owned transmission networks. In this way, pricing and investments of transmission systems are the most important problems [9, 10] together with the rules allowing their shared use. One of the most important areas that need an increased

attention is the reliability assessment of transmission systems by taking into account both the respective generation and transmission facilities. The impact of transmission services can be quite significant on both the load-point and the system reliability performance. The reliability evaluation techniques at Hierarchical Level Two (HLII) [3] can be utilized to assess the impact of wheeling transactions on the system adequacy. Such a study has been published using a simplified analytical technique [11]. However, a more detailed system representation is always necessary considering the particular operating features of transmission services so that their impact on the reliability performance of an electric power system can be explored [12]. Pricing of transmission services plays a crucial role in determining whether providing transmission services is economically beneficial to both the wheeling utility and customers. Some methods have been reported in the literature to allocate transmission fixed costs [9,10,13,14] and can be classified as embedded cost, incremental cost and composite embedded/ incremental cost methods. The cost to deliver electric energy varies as a function of time, system status and location within a power system.

6.4.2 Main Features of the Reliability and Cost Allocation Methods

In the competitive electric energy market, several players have access to the transmission networks even though in a regulated way. This means that the commercial and the energy/power wheeling transactions through the transmission networks become more and more frequent tasks, superimposing the original network task aimed at feeding the demand. The task of quickly and accurately evaluating the merits of wheeling transactions is becoming an important function of utility system planners and operators. This is because it affects vital system attributes (security, reliability, losses, etc.), puts a strain on the existing transmission network and may restrict the economic generation dispatching. Furthermore, the reliability performance of the transmission network together with the reliability indices of service supplied to system customers constitute one of the major aspects that are taken into account in the system planning and operating phases. It is therefore evident that there is a need for planning and operating considerations that must be followed by all the various transmission system customers in order to assure that all of them will be able to operate reliably and safely together.

A transmission transaction refers to the transmission component of the service being provided and it is associated with a power sale, a power purchase or a wheeling transaction. The following two categories of transmission transactions are mainly used which affect differently the reliability assessment of the transmission network being used:

- **Firm transmission transactions:** These are not subject to discretionary interruptions and they entail reservation of capacity on transmission facilities to meet transaction needs. They are the result of contractual agreements between the transmission system operator (or owner) and the wheeling customers.
- **Non - Firm transmission transactions:** They may be subject to load curtailment at the appropriate direction of the responsible body.

A wheeling customer can be connected anywhere in the transmission system which must transmit the power injected to the input busbars of wheeling transactions to appropriate output busbars. However, in outage conditions, the system may not be able to transmit the full

amount of power required by each transaction due to limitations in the transmission circuits after the outage has occurred. The generation/load patterns of each wheeling customer have usually two elements of equal magnitude, the power injection and the contracted load. These patterns are always balanced which means that the total injection equals total load. The operating characteristics of each wheeling transaction can be modeled by assuming that its operation will follow a daily capacity curve, which may not exist in certain days in each week or certain weeks in the year. This curve indicates the capacity agreed to be transmitted by the utility and is determined by the respective number of capacity levels given for the twenty-four time intervals being considered. The transmission network must ensure open access in generation services and, in order to achieve this, it should provide adequate service charges, which remunerate investments and induce the best overall use of the system resources. Transmission of electricity must be offered and priced separately from the power itself and delivery of power must stand on its own as a business.

Several criteria have been used to justify transmission charge schemes such as simplicity, fairness of cost allocations, economic theory and others [13], [15]. The accurate knowledge of the actual costs of providing transmission transactions is vital to transmission network operators for a number of reasons such as the economic aspects of operating decisions and the business decisions with regard to operations, investment and commitments to customers [15].

The cost of power delivered at a transmission network busbar varies from place to place within the network and can be calculated using the following 'unbundled' services:

Total cost = energy cost + transmission cost + losses cost + ancillary services cost + dispatching cost + congestion cost
where:

- The energy cost is the system production cost (fixed and variable) that varies according to the time period of the day being concerned and the respective generating units in operation.
- The transmission cost includes the capital recovery cost of the system equipment and the maintenance cost.
- The losses cost is the cost of producing additional generation for supplying the transmission network losses that vary with loading, flow pattern, location and distance. All network users should pay this cost.
- The ancillary services cost is the cost for providing all services that are required for the safe and reliable operation of the system which include the generation reserve, the load frequency control, the voltage control, the system restoration, etc. The most important element of this cost is the generation reserve cost which has two parts covering the variable cost of the spinning generating units and the fixed cost of all the system stand-by generating units. This cost is allocated to all system busbars in proportion of their load demand.
- The dispatching cost includes the charges for the transmission system operator's services of scheduling, controlling and dispatching the transmission system.
- The congestion cost is associated with the transmission network equipment and security constraints and concerns the system operator actions to redispatch the generation in order to accommodate the additional transmission transactions. This cost changes the marginal cost of power at some system busbars and it is allocated to each new transaction.

The mesh structure of transmission networks provides a large number of possible routes by which electrical power can flow from the sources to the loads. Until recently, the question of tracing electricity was of a limited interest. However, the open access requirements have posed new aspects of system operation and the problem of tracing electricity gains additional importance. Computational techniques have been published [16, 17] that allow the tracing of electricity flow in meshed networks. Another more efficient technique was also developed at NTUA [18,19]. All these three techniques produce appropriate tables that show how much of the power output from a particular generating unit goes to a particular load and the contributions of individual generating units or load to individual line flows. Apart from giving additional insight into how power flows in the network, these techniques can be used as a tool for determining the charges for transmission losses and the actual usage of the system by a particular generating unit or load. Using these techniques for each generating unit bus, the set of buses is deduced that are reached by power produced by this generating unit. Power from a generating unit reaches a particular bus if it is possible to find a path through the network from the generating unit to the bus for which the direction of travel is always consistent with the direction of the flow as computed by a power flow computer program. The same techniques can be used to contribute the load of each busbar and the system losses to individual generating units in the network. Therefore, the geographically differentiated price charged to consumers could be computed on the basis of the relative contribution of each generating unit to their load and the price of each of these generating units.

The three tracing techniques are topological in nature that means that they deal with a general transportation problem of how the flows are distributed in a meshed network. The basic assumption used by tracing algorithms is the proportional sharing principle. A proportional sharing principle is assumed which states that each network node is a perfect ‘mixer’ of incoming flows so that the power flow leaving a node contains the same proportion of the inflows as the total nodal inflow. This is true since it is impossible to identify which particular inflowing electron goes into which particular outgoing branch and seems to agree with the generally accepted view that electricity is indistinguishable. Figure 6.1 presents an example for implementing the above-described principle. There are four branches that are connected to node i (nodes j, k, l, m are the other nodes). The total power flowing through node i is 100 MW while 40 MW and 60 MW are supplied from branches j-i and k-i respectively. According to the assumption being made, 70 MW flow through branch i-m and include 28 MW being supplied by branch j-i ($70 \times 40 / 100 = 28$) and 42 MW being supplied by branch k-i ($70 \times 60 / 100 = 42$) while 30 MW flow through branch i-l and include 12 MW being supplied by branch j-i ($30 \times 40 / 100 = 12$) and 18 MW being supplied by branch k-i ($30 \times 60 / 100 = 18$).

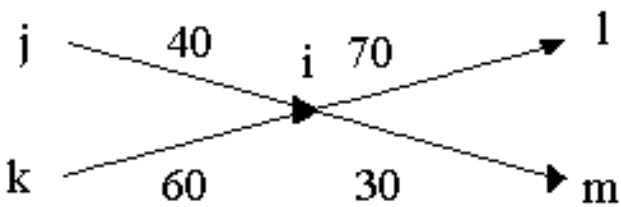


Fig. 6.1. Node with 100 MW power flow (power values in MW)

Technique No. 1 [16] calculates a table A from the equation $AuP = PG$ where P is the vector of nodal through-flows, PG is the vector of nodal generations and the (i, j) element of the sparse and nonsymmetrical matrix A is given as:

$$[A_u]_{ij} = \begin{cases} 1 & \text{for } i = j \\ -c_{ji} = -|P_{j-i}|/P_j & \text{for } j \in d_i^{(u)} \\ 0 & \text{otherwise} \end{cases} \quad (1)$$

assuming that $d_i(u)$ is the set of nodes supplying directly node i. If A^{-1} exists, the ith element of vector is

$$P_i = \sum_{k=1}^n [A_u^{-1}]_{ik} P_{G_k} \quad \text{for } i=1,2,\dots,n \quad (2)$$

where n is the number of system nodes. A line outflow in line j from node i can be calculated using the proportional sharing principle, as:

$$|P_j| = \frac{|P_j|}{P_i} P_i = \frac{|P_j|}{P_i} \sum_{k=1}^n [A_u^{-1}]_{ik} P_{G_k} = \sum_{k=1}^n b_{kj} P_{G_k} \quad (3)$$

In this equation, the coefficient b_{kj} shows the respective contributions of each generating unit k to the power flow of each line j. The load demand P_{L_i} can be calculated from P_i as:

$$P_{L_i} = \frac{P_{L_i}}{P_i} P_i = \frac{P_{L_i}}{P_i} \sum_{k=1}^n [A_u^{-1}]_{ik} P_{G_k} = \sum_{k=1}^n a_{ki} P_{G_k} \quad (4)$$

In this equation, the coefficient a_{ki} shows the respective contributions of each generating unit k to the i load demand and can be used to trace where the power of a particular load comes.

Technique No. 2 [17] is based on a set of definitions which are domains (set of buses getting power from a particular generating unit), commons (set of contiguous buses getting power from the same set of generating units), links (lines connecting commons), inflow (the sum of the generation by sources connected to busses located in this common and of the power imported in this common from others commons by links) and outflow (the sum of the loads connected to the busses located in this common and of the power exported through links from this commons to others commons). The basic assumption used in this method is the proportional sharing principle which assumes that for a given common, the proportion of the inflow which can be traced to generating unit i is equal to proportion of every bus load and to every line flow within this common and equal to the proportion of the outflow of this common. If C_{km} is the contribution of generating unit k to the common m, C_{kn} is the contribution of generating unit k to the common n, F_{mn} is the flow of the link between commons m and n, F_{kmn} is the flow on the link between commons m and n due to generating unit k and I_n is the inflow of common n, the following equations can be derived:

$$F_{kmn} = C_{km} * F_{mn} \quad (5)$$

$$I_n = \sum_m F_{mn} \quad (6)$$

$$C_{kn} = \frac{\sum_m F_{kmn}}{I_n} \quad (7)$$

Knowing the common to which a bus belongs and the contributions of each generating unit to each common, the power that each generating unit contributes to each load can be computed. It also makes it possible to compute what proportion of the use of each line can be apportioned to each generating unit. For lines linking busses in separate commons, the proportion of usage should be based on the contribution of the generating unit to the common, which is the starting end of this line. Therefore, the coefficient $a_{ki}=C_{kn}$ shows the respective contributions of each generating unit k to the i load demand which is located within common n . The coefficient $b_{kj}=C_{kn}$ shows the respective contributions of each generating unit k to the power flow of each line j which is located within common n . For line j linking commons, the coefficient $b_{kj}=C_{kn}$ shows the respective contributions of each generating unit k to the power flow of line j , which the sending end is the n common.

The developed technique No. 3 [18,19] is based on the computation of two characteristic tables A and B which express the respective contributions of each generating unit k to the load of each bus i and power flow of each line j . The coefficients of these tables (a_{ki} and b_{kj}) are computed as follows:

$$d_{ki} = \sum_j d_{km} \frac{P_j}{P_{om}} \quad (8)$$

where P_j is the power flow in line j supplying bus k , P_{om} is the total nodal flow of node m that is the sending end of line j

$$a_{ki} = d_{ki} \frac{L_i}{P_{oi}} \quad (9)$$

where L_i and P_{oi} is the load and the total inflow of bus i

$$b_{kj} = d_{ks} \frac{P_j}{P_{os}} \quad (10)$$

and
where P_j is the power flow of line j and P_{os} is the total inflow of bus s , which is the sending end of the line j . This iterative procedure starts from the corresponding generating unit busbar where the coefficient d_{kk} becomes unity and continues the computation of coefficients a_{ki} and b_{kj} following the direction of electricity flow through the network. With the assumption that generating units contribute to the losses in a line in proportion of their use of this line, this method computes the proportion of the generating unit output that is dissipated. The proportion of the total system load, the total transmission use and the total system losses contributed to each generating unit can also be computed using the coefficients a_{ki} and b_{kj} .

6.4.3 Computational Methodology

An improved computational method was developed at NTUA applying the features of the Monte - Carlo sequential approach [18,19]. Its objective is to integrate the operating aspects of wheeling transactions into the reliability and cost assessment of composite generation and transmission power systems. An important aspect of this method is the incorporation of independent computational techniques that incorporate the three alternative techniques mentioned before for tracing the power flows through the meshed transmission networks. This approach has the following main steps:

- For each generating unit bus, the set of buses is deduced which are reached by power produced by this generating unit. Power from a generating unit reaches a particular bus if it is possible to find a path through the network from the generating unit to the bus for which the direction of travel is always consistent with the direction of the flow as computed by a power flow computer program.
- The amount of power that each generating unit contributes to each load is computed.
- The proportion of the use of each branch that can be apportioned to each generating unit is computed.
- Since it is reasonable to assume that generating units contribute to the losses in a branch, the proportion of each generating unit output that can be dissipated in system losses is computed.
- The ancillary services cost is computed considering only the generation reserve cost. The ancillary services cost and the dispatching cost are distributed to each system bus, proportionately to its load demand.
- The total energy cost of each generating unit is allocated to all loads that are being supplied by it.
- The transmission network limitations (overloaded branches) are deduced applying a suitable DC load flow algorithm. This is mainly for limiting the computational time being required for the significant number of such calculations. The generating units that are "responsible" for these limitations are identified and appropriate operating procedures are simulated for alleviating the overloads in the most economical way. The first procedure to be considered is the generation rescheduling and, if it is still necessary, the procedure for load curtailment is applied at appropriate busbars. When all these limitations have been removed, the total system cost is calculated by applying the above described steps. The additional cost provides the congestion cost which is allocated appropriately to all "responsible" generating units while the cost of all the other generating units is also modified.
- A proportional sharing principle is assumed which states that each network node is a perfect 'mixer' of incoming flows so that the power flow leaving a node contains the same proportion of the inflows as the total nodal inflow. This is true since it is impossible to identify which particular inflowing electron goes into which particular outgoing branch and seems to agree with the generally accepted view that electricity is indistinguishable.

Furthermore, the basic features of the developed methodology are the following:

1. Each wheeling transaction is modeled as an equivalent generating unit connected to the input busbar of the transaction. This unit is assumed to be 100% reliable and its output is variable since, in each hour of the simulation period, its output capacity level is determined by the capacity curve being agreed. Furthermore, an additional load is assumed to be connected at the output busbar of the transaction and is equal to the capacity of the equivalent generating unit in each hour of the simulation period.
2. The existing generation rescheduling technique has been extended to include the particular operating characteristics of the wheeling transactions. The equivalent generating units of the wheeling transactions are assigned the lowest priority orders in the respective list used for generation redispatch. Furthermore, a certain amount of spinning reserve is always assigned applying the reliability criterion of satisfying the loss of the largest generating unit in operation.
3. The existing branch overloading technique has been extended so that it can take into account the wheeling transactions. In outage conditions, the generation/load patterns of the non-firm wheeling transactions may be decreased up to the firm capacity percentage being agreed in order to alleviate the possible overloads of the system branches.
4. In each hour of the simulation period, the network branch flows are calculated in two steps applying the corresponding computational technique (transmission system, wheeling transaction). The overall network branch flows are calculated appropriately. Additionally, the relative contributions of each generating unit to each system load and system branch are calculated together with the allocation of transmission losses to each generating unit. The technique being developed for tracing electricity is used for this purpose.
5. The operational performance of wheeling transactions is quantified by taking into account two types of events that cause a system failure to transmit the capacity agreed for each wheeling transaction due to the respective system limitations (split system, overloaded branches).

The prime objective of the developed computational methodology is to calculate appropriate indices that quantify the operational and reliability performance of a power transmission system accommodating wheeling transactions together with the respective indices for each transaction under consideration. These indices refer to system adequacy and can be described as follows while they have the corresponding units and acronyms given in parentheses:

- Four sets of reliability indices: The first set forms load-point and system indices which reflect their respective adequacy. The second set forms load-point and system interruption indices which reflect the characteristics of the interruptions occurred while the third set of indices is calculated for each hydroelectric plant. The system health indices are included in the fourth set.
- Four indices quantifying the transmission system capability and the operational performance of wheeling transactions:

- Expected annual energy of wheeling transactions being performed (EETRS) in GWh/year.
- Expected frequency of wheeling transactions not being performed (FNTRS) in occurrences/year.
- Expected annual duration of wheeling transactions not being performed (DNTRS) in hours/year.
- Expected annual not transmitted energy of wheeling transactions (ENTRS) in GWh/year.

This set of indices is calculated for each wheeling customer separately and for all categories of events considered in the above paragraph that cause a wheeling transaction not to be performed. Furthermore, additional information can be obtained concerning the transmission branches that were overloaded due to the wheeling transactions as well as the expected frequency of these events given in occurrences/year.

- Additional information are obtained concerning the system production cost (PC in k€/year) and the congestion cost (CNG in k€/year) of the generating units that were required to be redispatched or started-up.
- Three indices concerning the application of reliability criterion of the level of spinning reserve of the system generating units and the respective cost being required:
 - Expected frequency of spinning reserve criterion not being satisfied (FLNSP) in occurrences/year.
 - Expected annual duration of spinning reserve criterion not being satisfied (EDNSP) in hours/year.
 - Expected annual cost of spinning reserve criterion being satisfied (CSPIN) in k€/year.
- Two characteristic tables indicating the relative contributions (in percentages) of each system generating unit to the load of each busbar and the relative contributions (in percentages) of each busbar load to the power output of each generating unit. Using these two tables, three overall indices are calculated expressing the contributions of each system generating unit (in percentages) to the total system load (CLOAD), system losses (CLOSS) and transmission cost (CTRANS). These three indices are also calculated for each wheeling transaction separately.
- Two additional characteristic tables A and B are calculated which indicate the relative contributions (in percentages) of each system generating unit to the load of each busbar and the relative contributions (in percentages) of each busbar load to the generation of each generating unit. A more effective computational procedure is used applying equations 1-3 which calculates three additional overall indices expressing the contributions of each system generating unit (in percentages) to the total system load (CLOAD), system losses (CLOSS) and transmission cost (CTRANS). These three indices are also calculated for each wheeling transaction separately.
- An additional index concerning the expected annual cost of power delivered to each load point together with the five parts in to which it is divided. Additionally, an hourly curve can be obtained for an average day of the year showing the cost variation of the power delivered to each system load-point.

6.4.4 Assessment Studies

The developed computational method was applied for conducting reliability assessment studies on the IEEE-RTS [20] that was modified slightly in order to consider wheeling transactions and evaluate their impact on the system reliability and cost indices. The IEEE-RTS was assumed to be a wheeling transmission system and one non-firm wheeling transaction was considered having a firm capacity of 70% of the agreed capacity (450 MW) that remains constant throughout a year. This transaction assumes an injection at bus 10 and removal at bus 20. Tables 6.7 and 6.8 present the generating unit contributions to system loads, lines and transmission use for the following six case studies:

Case 1: Tracing technique No. 1 is used, no wheeling transactions.

Case 2: Tracing technique No. 2 is used, no wheeling transactions.

Case 3: Tracing technique No. 3 is used, no wheeling transactions.

Case 4: As in Case 1, one wheeling transaction exists.

Case 5: As in Case 2, one wheeling transaction exists.

Case 6: As in Case 3, one wheeling transaction exists.

Tables 6.7 and 6.8 show that the results of Case 3 are identical with those obtained for Case 1 and very close to the respective ones of Case 2. However, the application of the tracing techniques No. 1 and No. 2 (equations 1 - 7) require a considerable amount of computational time when they are applied in large practical systems because they need the inversion of a very large in size matrix. This problem has been overcome by applying the developed tracing technique No. 3 and the time being required is decreased significantly. This allows the efficient incorporation of this procedure into the computational method for the reliability and cost assessment of composite power systems (Case 3).

The full set of system indices described in the previous section was evaluated for the above six case studies and the obtained system results are presented in Table 6.9 while the reliability indices of certain load-points are presented in Table 6.10. These results clearly indicate that the wheeling transactions agreed and their specific design and operating features employed significantly affect the reliability and cost indices of the utility system. Each of these factors has a different effect on the system transmission capability. A considerable number of comments and conclusions can be drawn from these results but the most important ones are the following:

- The level of firm load to be satisfied in each wheeling transaction as well as the profile of its capacity curve affect the reliability indices but their impact is not significant. However, the indices of the wheeling transactions are affected in a greater extent.
- An important system characteristic is the selection of system busbars that will become the input and output busbars of the wheeling transactions agreed.
- The wheeling customer indices are also affected by the system topology and characteristics.
- The differences obtained in the index of the system congestion cost (CNG) may be positive or negative according to the characteristics of each wheeling transaction but

their actual numerical values are not significant enough. However, this situation may change in other system configurations.

- The reliability indices of transmission system load-points may be affected by the wheeling transaction being applied as is noticed by the results in Table 6.10 but the actual impact differs.
- The contributions of generating units to busbar loads and cost indices depend on their size and, additionally, on the priority level of dispatching them (Table 6.7).
- The cost of power delivered at system busbars depends mainly on the production cost of the generating units located near to the busbar (Table 6.9).

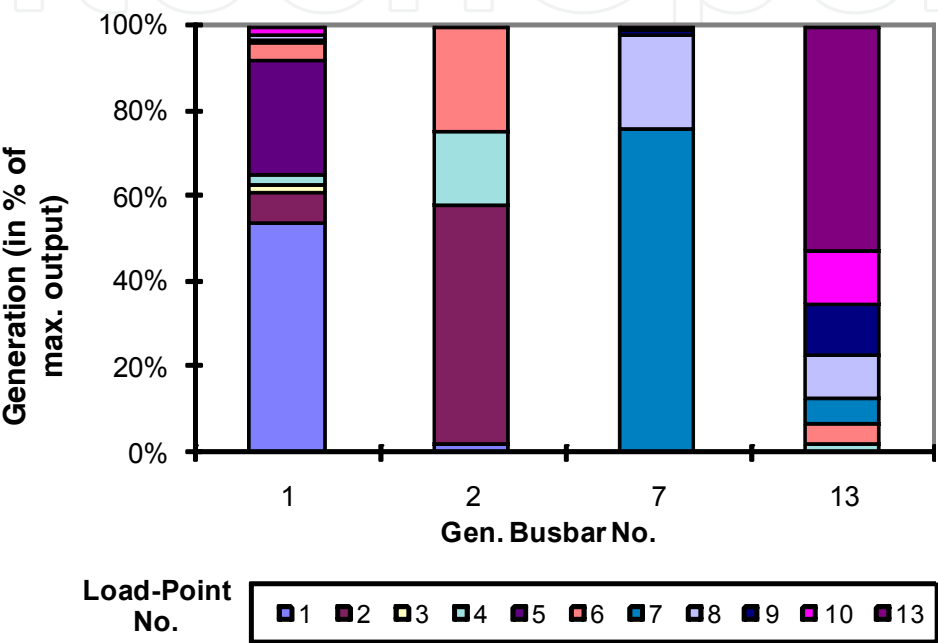


Fig. 6.2. Relative contributions of busbar loads to each system generating unit output (Case 3)

Bus No	Gen. MW	Case 1		Case 2		Case 3	
		Load4	Line6	Load4	Line6	Load4	Line6
1	192	2.8	0.5	2.8	0.6	2.8	0.5
2	192	20.0	0.0	19.8	0.4	20.0	0.0
7	300	0.0	1.4	0.0	1.4	0.0	1.4
13	591	2.3	5.2	2.9	6.5	2.3	5.2
15	215	2.6	2.6	2.4	3.0	2.6	2.6
16	155	2.7	4.7	2.9	4.4	2.7	4.7
18	400	9.9	12.0	12.1	13.4	9.9	12.0
21	400	12.5	11.2	11.6	12.8	12.5	11.2
22	300	13.1	14.9	11.5	13.2	13.1	14.9
23	660	34.1	47.5	34.0	44.3	34.1	47.5
		100.0	100.0	100.0	100.00	100.0	100.00

Table 6.7. Generating Unit Contributions to Load L4 and Line 6 (in %)

A greater number of detailed sensitivity studies can be easily conducted for establishing the impact of each system parameter and obtaining a more realistic reliability assessment. Additionally, Figures 6.2 and 6.3 show the relative contributions of busbar loads to each system generating unit output and the relative contributions of each generating unit output to system load, transmission use and losses for Case 3. It can be noticed that these generating unit output contributions are larger in the load of busbars and loading of branches that are located near to the generating units busbars.

Bus No	Gen. MW	Case 1		Case 2		Case 3	
		LOAD	TRAN.	LOAD	TRAN.	LOAD	TRAN.
1	192	5.19	2.59	5.19	2.58	5.19	2.59
2	192	4.54	3.11	4.54	3.03	4.54	3.11
7	300	4.29	0.05	4.29	0.05	4.29	0.05
13	591	8.92	1.96	8.92	1.93	8.92	1.96
15	215	5.84	3.10	5.84	3.22	5.84	3.10
16	155	5.81	2.29	5.81	2.29	5.81	2.29
18	400	16.46	9.55	16.46	10.66	16.46	9.55
21	400	16.46	16.68	16.46	17.62	16.46	16.68
22	300	11.70	26.55	11.70	25.98	11.70	26.55
23	660	20.79	34.12	20.79	32.69	20.79	34.12
10	450	0	0	0	0	0	0
		100.0	100.0	100.0	100.0	100.0	100.0
Bus No	Gen. MW	Case 4		Case 5		Case 6	
		LOAD	TRAN.	LOAD	TRAN.	LOAD	TRAN.
1	192	4.38	3.42	4.38	3.39	4.38	3.42
2	192	3.83	3.40	3.84	3.30	3.83	3.40
7	300	3.62	0.05	3.63	0.05	3.62	0.05
13	591	7.52	2.43	7.53	2.29	7.52	2.43
15	215	4.93	2.65	4.93	2.65	4.93	2.65
16	155	4.90	2.08	4.93	2.07	4.90	2.08
18	400	13.89	7.70	13.88	8.32	13.89	7.70
21	400	13.88	15.42	13.87	15.35	13.88	15.42
22	300	9.87	24.77	9.86	23.94	9.87	24.77
23	660	17.54	18.46	17.53	18.11	17.54	18.46
10	450	15.64	19.62	15.62	20.53	15.64	19.62
		100.0	100.0	100.0	100.00	100.0	100.00

Table 6.8. Generating Unit Contributions to System Loads and Transmission Use (in %)

System and Wheeling Transactions						
Case Study Index	1	2	3	4	5	6
<i>Utility system</i>						
LOLE	19.221	19.221	19.221	19.35	19.35	19.35
LOEE	2271.1	2271.1	2271.1	2335.6	2335.6	2335.6
EDNS	70.26	70.26	70.26	76.31	76.31	76.31
FLOL	4.266	4.266	4.266	4.297	4.297	4.297
EIR	.99985	.99985	.99985	.99985	.99985	.99985
PC-CNG	11973	11973	11973	-7.83	-7.83	-7.83
CLOAD	3	3	3	84.37	84.39	84.37
CTRANS	100.0	100.0	100.0	80.39	79.46	80.39
CLOSS	100.0	100.0	100.0	75.17	75.29	75.17
FLNSP	100.0	100.0	100.0	66.00	66.00	66.00
EDNSP	66.00	66.00	66.00	386.17	386.17	386.17
CSPIN	386.17	386.17	386.17	13760	13760	13760
	13760	13760	13760			
<i>Wheeling Customer 1</i>						
EETRS				3930.9	3930.9	3930.9
ENTRS				0.0857	0.0857	0.0857
DNTRS				1.786	1.786	1.786
FNTRS				0.234	0.234	0.234
CLOAD				15.63	15.61	15.63
CTRANS				19.61	20.54	19.61
CLOSS				24.83	24.71	24.83

Table 6.9. Reliability and Operational Indices for the Transmission

Bus No.	L4	L7	L8	L9	L15	L18
Case 1						
LOLE	0.2	19.0	14.1	13.3	14.9	14.1
LOEE	1.3	116.1	93.5	88.1	499.3	624.7
EDNS	0.2	4.4	4.5	4.4	18.4	21.7
FLOL	0.1	4.3	3.3	3.1	3.3	3.1
Case 4						
LOLE	0.2	19.7	14.7	13.9	15.3	14.7
LOEE	0.6	116.8	96.2	89.8	510.4	640.5
EDNS	0.2	4.4	4.6	4.5	19.1	21.9
FLOL	0.1	4.4	3.4	3.2	3.4	3.3

Table 6.10. Reliability Indices of Transmission System Load-Points

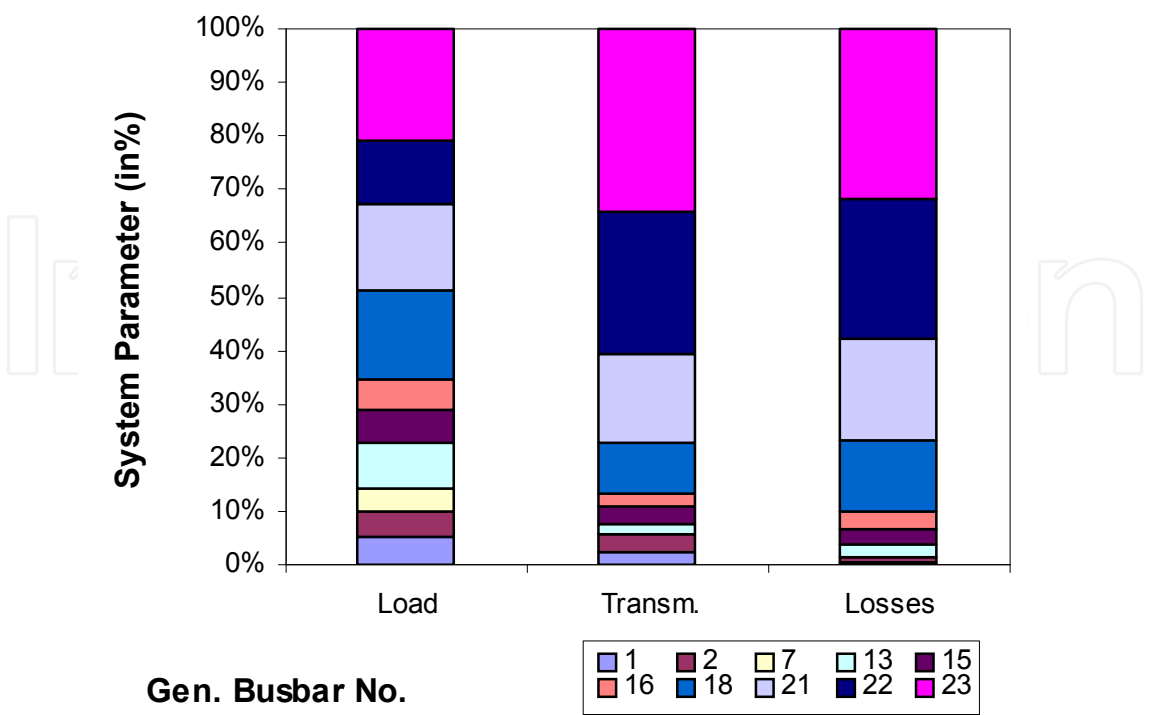


Fig. 6.3. Relative contributions of each generating unit output to system load, transmission use and losses (Case 3)

6.5 Conclusions

The application of renewable energy sources in isolated power systems may significantly affect their operational characteristics and inevitably their reliability performance. This Chapter describes the main concepts and features of an efficient computational methodology that is based on the sequential Monte - Carlo simulation approach. This methodology can be used as a useful tool for quantifying the reliability and operational performance of isolated power systems with high penetration of renewable sources. It also presents the results that were obtained from the reliability assessment studies conducted for an isolated power system which is based on the power system of a Greek island. It is shown that the system adequacy is critically dependent on the wind penetration margin that is assumed by the system operator. In addition, a sufficiently large percentage of spinning reserve being supplied by the system conventional generating units can improve the system reliability indices and prevent the occurrence of dynamically unstable situations in cases of a sudden loss of a large amount of power being produced by the wind generating units. Furthermore, it is clearly shown that the addition of small hydroelectric generating units improves the reliability performance of the system according to their characteristics.

Additionally, this Chapter describes the main concepts and features of an improved computational methodology that can be used for conducting reliability and cost assessment studies of transmission systems under the framework of the competitive energy market. This methodology is based on the sequential Monte - Carlo simulation approach and can analyse systems with any given configuration and operational features. An important

emphasis is given in the realistic simulation of the operational behaviour of both the transmission system and the wheeling transactions so that a more accurate reliability assessment is achieved. For this purpose, three alternative techniques for power tracing are incorporated. An extended set of indices is calculated to quantify the system reliability performance and transmission capability and they can be used to measure the changes obtained in system reliability due to the wheeling transactions being accommodated. The analysis of various case studies is also presented for a modified IEEE-RTS that includes wheeling transactions. Finally, the obtained results demonstrate clearly the increased information being gained.

6.6 Acknowledgements

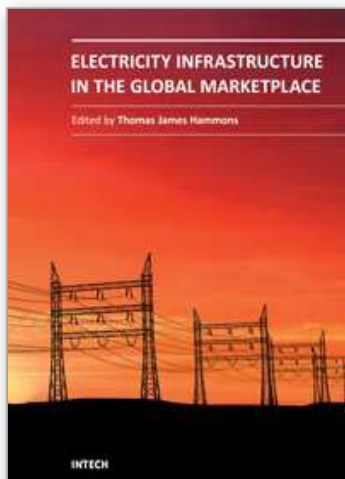
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This book discusses trends in the energy industries of emerging economies in all continents. It provides the forum for dissemination and exchange of scientific and engineering information on the theoretical generic and applied areas of scientific and engineering knowledge relating to electrical power infrastructure in the global marketplace. It is a timely reference to modern deregulated energy infrastructure: challenges of restructuring electricity markets in emerging economies. The topics deal with nuclear and hydropower worldwide; biomass; energy potential of the oceans; geothermal energy; reliability; wind power; integrating renewable and dispersed electricity into the grid; electricity markets in Africa, Asia, China, Europe, India, Russia, and in South America. In addition the merits of GHG programs and markets on the electrical power industry, market mechanisms and supply adequacy in hydro-dominated countries in Latin America, energy issues under deregulated environments (including insurance issues) and the African Union and new partnerships for Africa's development is considered.

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