SYSTEM OPERATION PERFORMANCE STANDARDS

TABLE OF CONTENTS:

PART 5: SYSTEM OPERARTION PERFORMANCE STANDARDS

1. SECTION: SYSTEM OPERATOR ACTIVITIES

1.1.1. The activities of the System Operator will be classified as follows:

(a) **Operation Planning**, where the system conditions for a next period are foreseen. Following aspects will be considered and evaluated:

(i) Load is forecasted.

(ii) Generation is scheduled, according with the minimum cost criteria and following the Merit Order given by the Bulk Supply Licensee.

(iii) Preventive and Corrective Maintenance of Generation Units and Transmission Equipment are scheduled trying to attend the Generation and Transmission Licensees requirements.

(iv) Ensure that the Security Criteria is achieved. In the contrary adopt the required decisions that may affect the above mentioned aspects.

(b) **Real Time Operation**, where the system is monitored and operated in Real Time, using the SCADA and other applications information:

(i) Under Normal Conditions, where economic criteria are used to operate, the system is monitored in order to verify that all relevant parameters are inside acceptable Operative Limits and, in case of contingencies, the security criteria enforced.

(ii) Under Alert Conditions, where security criteria is used to operate and some parameters are outside their Operative Limits or other Security Criteria is not achieved, the System Operator shall take appropriate actions to take the system back to normal conditions.

(iii) Under Emergency Conditions, where restoration criteria is used to operate, the system has some or all areas in blackout or areas where the values are out of acceptable limits, the System Operator shall restore the system, in the shortest period of time compatible with the generation and interconnection capacity and network availability.

1.1.2. During the Operation Planning and Real Time Operation, the System Operator will collect and produce an important amount of information, which shall be analysed and stored for auditing proposes or future use. Some part of this information shall be made available, in agreed time, contents and format, to

(i) Ministry of Energy and Mineral Resources

(ii) Electricity Sector Regulatory Commission

(iii) Generation, Transmission, Distribution and Bulk Supply Licensees

(iv) General Public

2. SECTION: OPERATION PLANNING PERFORMANCE

2.1. LOAD FORECAST PERFORMANCE INDICATORS

2.1.1. As required by the Grid Code (OC1, OC3 and SDC1), the System Operator shall forecast the Gross Demand at different time frame levels:

(a) Multiyear for network expansion and long term generation requirements.

(b) Yearly for medium term studies

(c) Weekly and daily for short term studies

2.1.2. Every week, before Wednesday 10:00 a.m., the System Operator shall produce an energy demand forecast (WADF) for each day of the following week, starting on Saturday. Copy of this weekly demand shall be submitted to the EMRC, and will be attached to Indicative Running Notification to be submitted to power producers with CDGUs, according with the provisions of the Grid Code (SDC1).

2.1.3. Every day the System Operator shall update the weekly load forecast for the following day, and produce a new hourly day ahead demand forecast (DADF). The DADF will be used in operational planning analysis and dispatch. A copy of the DADF will be submitted daily to the EMRC in electronic format before 2:00 p.m.

2.1.4. Forecasted demand values shall be compared with actual values at the time actual data will be available. Forecasts quality will be assessed through the evaluation of the difference between the forecasted demand values (F_v) and actual demand values (A_v) over a predefined period of time, and will be evaluated using six Performance Indicators:

(a) **MAE_{DA}** (Mean Absolute Error – Day Ahead Forecast): The average value of the absolute error series of the day ahead forecasted demand, calculated without sign.

(b) **MAE_{WA}** (Mean Absolute Error – Week Ahead Forecast): The average value of the absolute error series of the week ahead forecasted demand, calculated without sign.

(c) **$MAPE_{DA}$ (**Mean Absolute Percent Error – Day Ahead Forecast): The average value of the relative errors series of the day ahead forecasted demand, calculated without sign.

(d) **$MAPE_{WA}$ (**Mean Absolute Percent Error – Week Ahead Forecast): The average value of the relative errors series of the week ahead forecasted demand, calculated without sign.

(e) $MARGIN_{DA}$ (90% Percentile of the Relative Error – Day Ahead Forecast): The absolute value of the relative error of the day ahead forecasted demand that is not exceeded by the 90 % of the values in the predefined period of time.

(f) $MARGIN_{WA}$ (90% Percentile of the Relative Error – Week Ahead Forecast): The absolute value of the relative error of the week ahead forecasted demand that is not exceeded by the 90 % of the values in the predefined period of time.

2.1.5. The calculation of the Load Forecast Performance Indicators will be done by the System Operation Licensee on a monthly and yearly basis. When calculated on a yearly basis, the pre-specified period of time mentioned above shall be considered as a calendar year.

When calculated on a monthly basis the pre-specified period shall be considered from the beginning of the calendar year up to the month the Performance Indicator is calculated.

2.1.6. The detailed description and mathematical formulation of overall Performance Indicators are established in Annex 1.

2.1.7. The EMRC will assign the numerical values for the tolerances of each Load Forecast Performance Indicator for the System Operation Licensee, taking into consideration past performance and a benchmarking with other international system operators.

2.1.8. The tolerances for the Load Forecast Performance Indicators shall be approved by the EMRC in each Tariff Review Period and may be different for each calendar year during such period. The tolerances to be used for the first Tariff Review Period are established in Annex 4.

2.2. GENERATION SCHEDULING

2.2.1. Generation scheduling is the activity that consists in determining the most appropriate loading of the CDGUs at each moment, in order to supply the forecasted demand at minimum cost, taking into account the required reserve and network constraints.

2.2.2. Generation scheduling shall be performed at two different time frame levels: at a week level (Week Ahead Generation Schedule - WAGS) and at a daily level (Day Ahead Generation Schedule - DAGS).

Week Ahead Generation Schedule

2.2.3. Based on the information supplied by the Bulk Supply Licensee, the System Operator is obliged to prepare a Week Ahead Generation Schedule and an energy balance statement, according with the criteria established in the Grid Code. This generation schedule will be the basis to construct the Indicative Running Notifications.

2.2.4. The Indicative Running Notifications will be sent by e-mail, internet posting or fax to each Generation Licensee before Wednesday 10:00 a.m. of the week before the actual dispatch will take place.

2.2.5. The Indicative Running Notification will cover the period Saturday 00:00 a.m. to Friday 12:00 p.m. of the following week it has been issued, and will include at least the following information for each individual CDGU:

(a) Date and time in which the unit is expected to be synchronized to the network

(b) Date and time in which the unit is expected to be de-synchronized from the network

(c) Expected load of the unit in the following week at least at:

(i) Daily minimum system Load

(ii) Daily morning peak load

(iii) Daily evening peak load

(d) Expected total generated energy in each day of the following week

(e) Expected amount of fuel to be used in each day of the following week

(f) Any other information the System Operator will consider relevant to be communicated to the Generation Licensee.

The Indicative Running Notification submitted to each Generation Licensee will contain dispatch information related to its generation units only.

2.2.6. Not later than Wednesday 1:00 p.m., the information of the WAGS finally developed by the System Operator will be submitted to the Bulk Supply Licensee, in order the total cost of the generation dispatch will be calculated (BS-WAGS Report). The information to be sent to the Bulk Supply Licensee shall include at least:

(a) Copies of the Indicative Running Notification submitted to each Generation Licensee

(b) Information regarding the changes in the merit order provided by the Bulk Supply Licensee that has been produced by the System Operator, with indications regarding their reasons. The reasons will be catalogued as:

(i) Network congestion

(ii) Network Security

(iii) New Availability Notices received after the information from the Bulk Supply Licensee was received

(iv) System test being or to be performed

(v) Ancillary services requirements

(vi) Technical constraints in the raise or lower rate of the CDGUs

(vii) Other reasons (with clear explanations)

2.2.7. Not later than Thursday 10:00 a.m. the Bulk Supply Licensee will communicate the System Operator the total cost associated with the decided WAGS. Once this information will be received, the System Operator will prepare a WAGS Resume Report that shall be send to the EMRC not later Thursday 2:00 p.m. each week, according with the formats described below (Monitoring and Control Section).

2.2.8. The System Operator is obliged to keep registers of the Indicative Running Notifications issued, and the BS-WAGS Reports during at least three (3) calendar years.

Day Ahead Generation Schedule

2.2.9. Based on the WAGS, and taken into consideration the Day Ahead Demand Forecast, the Day Ahead Amended Availability Notices (or any other Availability Notice received since the moment the Indicative Running Notifications have been issued) received from the Generation Licensees, and the ancillary services required to safe and securely operate the system as indicated in Ancillary Service conditions, the System Operator is obliged to prepare a Day Ahead Generation Schedule, according with the criteria established in the Grid Code. This generation schedule will be the basis to construct the Daily Indicative Running Notifications (DIRN).

2.2.10. The DIRNs will be sent by e-mail, internet posting or fax to each Generation Licensee before 12:00 a.m. of the day before the actual dispatch will take place.

2.2.11. The DIRN will cover the period 00:00 a.m. to 12:00 p.m. of the following day it has been issued, and will include at least the following information for each individual CDGU:

(a) Date and time in which the unit is expected to be synchronized to the network

(b) Date and time in which the unit is expected to be de-synchronized from the network

(c) Expected load of the unit, for each hour of the following day (24 values)

(d) Assigned secondary reserve to the unit in the following day (24 values)

(e) Assigned tertiary reserve to the unit in the following day (24 values)

(f) Expected total generated energy in the following day

(g) Expected amount of fuel to be used in the following day

(h) Any other information the System Operator will consider relevant to be communicated to the Generation Licensee.

The DIRN submitted to each Generation Licensee will contain dispatch information related to its generation units only.

2.2.12. The information of the DAGS will be submitted to the Bulk Supply Licensee, in order the total cost of the generation dispatch will be calculated (BS-DAGS Report). The information to be sent to the Bulk Supply Licensee shall include at least:

(a) Copies of the DIRNs submitted to each Generation Licensee

(b) Information regarding the changes in the merit order required to provide adequately Ancillary Services and safe and reliable operation of the system.

2.2.13. Not later than Thursday 2:00 p.m. every day, the Bulk Supply Licensee will communicate the System Operator the total cost associated with the decided DAGS. Once this information will be received, the System Operator will prepare a DAGS Resume Report that shall be send to the EMRC not later than 3:00 p.m. every day, according with the formats described below (Monitoring and Control Section).

2.2.14. The System Operator is obliged to keep registers of the Daily Indicative Running Notifications issued, and the BS-DAGS Reports during at least three (3) calendar years.

Generation Scheduling Performance Indicators

2.2.15. Week Ahead and Day Ahead Generation Scheduling shall be compared with actual generation scheduling at the time actual data will be available. Scheduling adequacy will be assessed through the evaluation of the difference between the forecasted cost values the week ahead (FC_{wa}), the forecasted cost values the day ahead (FC_{da}), and actual cost values (AC) over a predefined period of time, and will be evaluated using four Performance Indicators:

(a) $\mathbf{MAD_{DA}}$ (Mean Absolute Difference – Day Ahead Scheduling Cost): The average value of the absolute differences series of the day ahead dispatch costs, calculated without sign.

(b) $\mathbf{MAD_{WA}}$ (Mean Absolute Difference – Week Ahead Scheduling Cost): The average value of the absolute differences series of the week ahead dispatch costs, calculated without sign.

(c) **$MAPD_{DA}$ (**Mean Absolute Percent Difference – Day Ahead Scheduling Costs): The average value of the relative differences series of the day ahead dispatch costs, calculated without sign.

(d) **$MAPD_{WA}$ (**Mean Absolute Percent Difference – Week Ahead Scheduling): The average value of the relative differences series of the week ahead dispatch costs, calculated without sign.

2.2.16. The calculation of the Generation Scheduling Performance Indicators will be done by the System Operation Licensee on a monthly and yearly basis. When calculated on a yearly basis, the pre-specified period of time mentioned above shall be considered as a calendar year. When calculated on a monthly basis the pre-specified period shall be considered from the beginning of the calendar year up to the month the Overall Performance Indicator is calculated.

2.2.17. The detailed description and mathematical formulation of overall Performance Indicators are established in Annex 2.

2.2.18. The EMRC will assign the numerical values for the tolerances of each Generation Scheduling Performance Indicator for the System Operation Licensee, taking into consideration past performance and a benchmarking with other international system operators.

2.2.19. The tolerances for the Generation Scheduling Performance Indicators shall be approved by the EMRC in each Tariff Review Period and may be different for each calendar year during such period. The tolerances to be used for the first Tariff Review Period are established in Annex 4.

2.3. ANCILLARY SERVICES

2.3.1. Ancillary Services are the services which are necessary to operate the system in a safe, secure and reliable way. These services, which will be procured by the System Operator, include:

(a) The provision of sufficient regulating capability to meet fluctuations in load during real time operation

(b) The provision of sufficient reserve capacity (secondary or spinning reserve) to maintain power the scheduled interchanges and system frequency in accordance with the specifications of the Grid Code, in case of network or generation Outages;

(c) The provision of sufficient reserve capacity to return the system to the Normal Conditions, and to restore the used reserves, after an Event that will require the use of all or part of the spinning reserve (tertiary or non-spinning reserve)

(d) The provision of reactive support to maintain the voltage in accordance with the Grid Code specifications

(e) The provision of black start capability to allow restoration of the power system after a complete or partial black out.

2.3.2. At the moment the System Operator will produce the Week Ahead Generation Dispatch and the Day Ahead Generation Dispatch, it shall make its best endeavors to assure the Ancillary Services stated in Condition 2.3.1 are provided according with the requirements stated in the Grid Code. In the cases that, due to expected generation availability or network conditions it will be impossible to achieve the requirements indicated in the Grid Code, this situation need to be clearly stated in the WAGS Resume Report or the DAGS Resume Report as correspond, submitted to the EMRC. In those cases, the operation of the system can not be catalogued as Normal Conditions.

2.3.3. In particular, the System Operator shall plan the future system operation (week ahead and day ahead) assuring that following Ancillary Services are adequately provided:

(a) ***Primary reserve:*** The amount of Primary Reserve and the expected response of the Primary Regulation will be determined taken into account the requirements indicated in the Grid Code (OC3 – Operating Reserve) or as an application of signed international agreements with the interconnected countries, whichever is higher. The System Operator shall determine the amount of Primary Regulation required for each foreseen operational circumstance, and to place Primary Reserve in specific selected units.

(b) ***Secondary Reserve:*** Secondary Reserve is designed to take over the Primary Reserve after and to return the frequency and interchanges to the targeted values. The amount of Secondary Reserve will be determined taken into account the requirements indicated in the Grid Code (OC3 – Operating Reserve) or as part of the signed international agreements between the interconnected countries, whichever is higher. The System Operator has the responsibility to calculate the amount of Secondary Reserve that required for each foreseen operational circumstance, and to place it under the direct Control of its AGC.

(c) ***Tertiary Reserve:*** There is not a specific criterion to determine the amount of Tertiary Reserve required. The System Operator shall program sufficient Tertiary Reserve to replace Secondary Reserve (if it is required) within a short period after an incident takes place, under credible circumstances. In conducting these analyses it shall be taken into account that being short in Tertiary Reserve will probably affect Secondary Regulation Performance.

(d) ***Voltage Control:*** The amount of reactive support, provided by the CDGUs, shall be enough to assure compliance with the Real Time Operation Performance Standards stated in Section 4.

(e) ***Black Start Capability:*** It shall verify that enough generation with black start capability is available in the system, and that it is not affected by any kind of restriction (such as fuel availability) or by maintenance operations in the transmission or distribution network.

2.3.4. The System Operator shall include in the Indicative Running Notifications and the Daily Indicative Running Notifications, to be submitted to the Generation Licensees, a detailed description of the expected amount of Ancillary Services that will be required from each CDGU to comply with this Performance Standards.

2.3.5. Although no specific Performance Indicator is associated with Ancillary Services programming, compliance with the above mentioned obligations will be assessed by the EMRC through:

(a) A statistical analysis of the daily and weekly information submitted by the System Operator (WAGS Resume Report, DAGS Resume Report and AOS Resume Report)

(b) Electric System performance following any significant incident.

(c) System Test performed

(d) Specific periodic analytical studies

(e) Periodic System Operator audits

(f) Based on the results of these analysis the EMRC may decide the convenience to introduce future Ancillary Services Performance Indicators, and its associated targets.

2.4. PLANNED OPERATIONAL RISK LEVEL

2.4.1. The Grid Code establishes the criteria the Transmission System shall be planned. The operation of the Power Systems must be performed in a way that will be compatible with the criteria it have been designed and constructed.

2.4.2. Not later than 6 months following the approval and issuing of this System Operation Performance Standards, the System Operation Licensee shall prepare and submit to the EMRC for approval, a report containing adequate description and rationale of the Minimum Security Criteria to be adopted when conducting operational studies, week and day ahead dispatches, and during real time operation. The Minimum Security Criteria shall not be less strict than the N-1 Criterion (but can be stricter including some credible “double contingencies” as consider appropriate), unless the economic burden imposed to the system in particular cases (specific contingencies) justifies a relaxation. In this case, enough supporting documentation shall be submitted, and a detailed Defense Plan prepared to cope with these potential situations.

2.4.3. The above mentioned Minimum Security Criteria should be updated by the System Operator from time to time to reflect changes produced in the Jordanian power system or in neighbouring countries, or in signed interconnection agreements. After the EMRC approval of this Minimum Security Criteria it will remain valid and enforceable, until a new one is submitted to the EMRC and approved.

2.4.4. Any equipment in the Transmission Network has a Nominal Limit (expressed in MVA or A) which is normally dependant on the equipment design and the external conditions. For this reason these limits can be different within the year depending on weather and temperature conditions.

2.4.5. In addition to the Nominal Limits, the Transmission Equipments can have an Operative Limit, which is dependant on the system condition. The Operative Limit will depend on the network conditions (equipment availability, generation profile, international power interchanges and voltage profile), and on Minimum Security Criteria utilized. Operational Limits will be equal or lower than the Nominal Limit. In the cases the Operative Limit is not specifically identified, it will be assumed that is identical to the Nominal Limit.

2.4.6. There will be a third group of limits, the Stress Limits, which are the flows (either in MVA or A) that can be maintained in a Transmission Equipment for a maximum of 20 minutes without equipment damage or reduction in its useful life.

2.4.7. The System Operator shall determine, for each Transmission Equipment in the Transmission System, the Nominal Limit (or Nominal Limits in the case their will be different under different external conditions), the Operational Limit (or limits) corresponding to most usual operating conditions, and the Stress Limits. These limits should be updated, from time to time, to reflect changes in the equipment characteristics, network conditions and Minimum Security Criteria utilized. They will be made available to any User which request such information, and submitted to the EMRC upon request or, at least, once every year. These Nominal and Operational Limits will be used by the System Operator when conducting the studies and analysis stated in 2.4.8.

2.4.8. Depending on the expected dispatch, generation or network availability and/or other abnormal operating conditions, the System Operator should determine a different set of Operative Limits for specific equipments, which will be used during the period the expected situation is expected to remain.

2.4.9. At the moment the System Operator will produce the Week Ahead Generation Dispatch and the Day Ahead Generation Dispatch, it shall make all necessary Operational Studies and analysis in order to verify the achievement of Minimum Security Criteria. If required, it will produce the required changes in the network configuration and/or dispatching generation out of merit order to reach the required security level. In the cases that, due to expected generation availability or network conditions it will be impossible to achieve the above mentioned security level, this situation need to be stated in the WAGS Resume Report or the DAGS Resume Report as correspond, submitted to the EMRC, indicating which security criteria is not satisfied, and the operation of the system can not be catalogued as Normal Conditions.

2.4.10. In conducting above mentioned studies, the System Operator can include some specific and credible “double contingencies”, it considered appropriate, according with the approved Minimum Security Criteria.

2.4.11. In the event that the Minimum Security Criteria is expected not to be achieved, and/or one or more of the “double contingencies” considered could generate an Emergency Condition in the Transmission System, the System Operator shall prepare a written contingency plan where the actions that shall be taken by the operator, in case that contingency took place, shall be identified and listed. In the cases the situation that generates the non achievement of the Minimum Security Level is expected to last more than 3 months, and/or the credible “double contingencies” considered can lead to an unacceptable situation in the Transmission System, the actions contained in the contingency plan shall be included in the Defence Plan.

2.5. RESTORATION AND DEMAND CONTROL PLANS

2.5.1. Restoration of the Electric System, after a major incident followed by a blackout or partial Blackout, is one of the key activities for a System Operator. Restoration of the Electric System shall be coordinated activity, under the System Operator responsibility, which will involve all the Users.

2.5.2. In order the restoration process will be as fast as possible, compatible with the system security and respecting all priorities and constrains, the System Operator shall coordinate with the involved Users a Restoration Plan with the contents indicated in the Grid Code.

This Restoration Plan may be amended and updated, from time to time to reflect the changes produced in the Electric System, and the lessons learnt from previous incidents and/or restoration processes.

2.5.3. In cases of insufficient generation to meet the expected or actual Load, breakdown or other operational problems, the System Operator shall initiate an automatic or manual demand reduction, as indicated in the Grid Code (OC7 – Demand Control).

2.5.4. In order the demand reduction process will be done in a coordinated and effective way, the System Operator shall coordinate with the Bulk Supply Licensee and the involved Users the required procedures to exercise it, and to compile the Demand Reduction Guidelines document, as indicated in the Grid Code. These guidelines will be submitted to the EMRC for approval.

2.5.5. Once the Demand Reduction Guidelines document is approved by the EMRC, the System Operator shall develop, and send to the EMRC for approval, the Demand Reduction Plans, for different levels of demand disconnection or reduction, according with the approved guidelines, as indicated in the Grid Code.

3. SECTION: REAL TIME OPERATION PERFORMANCE

3.1. FREQUENCY

3.1.1. Although the frequency is one of the most important parameters to be controlled, and a key factor in the quality of service, frequency control performance is a shared responsibility among the system operators of the interconnected systems. While interconnected with Syria and/or Egypt, the System Operator will be almost unable to control the frequency in Jordan due to the reduced size of Jordan Electrical System compared with the LEJSL System.

3.1.2. In the circumstances where the Jordanian Electric System is operated isolated from the LEJSL System, control of frequency will became a full responsibility of the System Operator. In those cases, the frequency must be maintained within the limits stated in the Grid Code.

3.1.3. When the Jordanian Electric System is operated isolated from the LEJSL System, the frequency shall be maintained:

(a) During Normal Conditions: 90 % of the time inside the limits established in the Grid Code, “Under Normal Operation” row.

(b) During Alarm or Emergency Conditions: 99% of the time inside the limits established in the Grid Code, “Under Stress Conditions” row.

3.1.4. The Performance Indicator that will measure compliance with this obligation, will be the relative amount of time, expressed in %, the frequency is outside the limits indicated in Condition 3.1.2., measured over the period the Electrical System operates isolated from LEJSL System.

3.1.5. The System Operator shall digitally register the frequency, taken at least one sample every 30 seconds. These values, with its associated name, date and time tag, will be registered and stored separately from other stored SCADA values, by the System Operator information system. Each sample shall have an identification tag that will allow to statistically processing them in two groups: Operation isolated from the LEJSL System, and operation interconnected with the LEJSL System. The System Operator shall keep these registers, at least during 2 (two) calendar years for auditing proposes.

3.1.6. The System Operator shall produce periodic statistical analysis of the stored data (at least once a month) in order to evaluate frequency control performance, and compliance with the obligation specified in 3.1.3 and to produce the monthly and yearly reports indicated in Monitoring and Control section of this Performance Standards.

3.2. SECONDARY REGULATION CONTROL

3.2.1. Secondary Regulation shall be exercised in a closed loop mode, by the System Operator's Automatic Generation Control (AGC).

3.2.2. Based on real time condition of the Electrical System, the System Operator has the responsibility to continuously confirm or amend the amount of Secondary Reserve programmed in the Day Ahead Generation Schedule, and to place it under the direct Control of the System Operator's AGC.

3.2.3. Compliance with Secondary Regulation performance will be based in the registered values of the Area Control Error (ACE). The System Operator shall digitally register the ACE, taken at least one sample every 30 seconds. These values, with its associated name, date and time tag, will be registered and stored separately from other stored SCADA values, by the System Operator information system. The System Operator shall keep these registers, at least during 2 (two) calendar years for auditing proposes.

3.2.4. The ACE must be permanently kept inside acceptable limits, and shall cross the zero value (ACE=0) at least once every 15 (fifteen) minutes during Normal Operation Conditions.

3.2.5. The Performance Indicators to measure System Operator performance in Secondary Regulation will be:

(a) **Average Time between Sign Changes (TBSCA):** It is the average time, during a pre-specified period, (expressed minutes) the Area Control Error crosses the zero value (change its sign).

(b) **95 Percentile of the Time Between Sign Changes (TBSC_95):** It is the value, during a pre-specified period, of the Time Between Sign Changes of the ACE series, that it is not exceeded by more than 5% of the registered values.

(c) **Maximum Time between Sign Changes (M_TBSC):** It is the maximum time, during a pre-specified period, (expressed minutes) the Area Control Error has crossed the zero value (change its sign).

3.2.6. The calculation of the Secondary Regulation Performance Indicators will be done by the System Operator on a monthly and yearly basis. When calculated on a yearly basis, the pre-specified period mentioned above shall be considered as a calendar year. When calculated on a monthly basis the pre-specified period shall be considered from the beginning of the calendar year up to the month the Performance Indicator is calculated.

The detailed description and procedures for calculating Secondary Regulation Performance Indicators are established in Annex 3.

3.2.7. The EMRC will assign the numerical values for the tolerances of each Secondary Regulation Performance Indicators taking into consideration past performance, signed international agreements and a benchmarking with international System Operators. The tolerances for the Performance Indicators shall be approved by the EMRC in each Tariff Review Period and may be different for each calendar year during such period. The tolerances to be used for the first Tariff Review Period are established in Annex 4.

3.3. VOLTAGE CONTROL

3.3.1. The System Operator shall make its best endeavours to maintain the voltage in the Transmission System, and in the 33 kV Bulk Supply Points under its control within the following range:

400 kV and 132 kV network (other than Bulk Supply Points)	Within the limits stated in the Grid Code (Normal Operation Conditions)
132 kV Bulk Supply Points	1. Within the limits established in the Operating Agreement. 2. Within the limits established in the Grid Code in the cases no specific indication is included in the Connection Agreement.
33 kV Bulk Supply Points	1. Within the limits established in the Operating Agreement. 2. Within the limits indicated in the Grid Code in the cases no specific indication is included in the Connection Agreement.

3.3.2. A Bulk Supply Point in 33 kV is considered to be under the System Operator Control if the Transmission Licensee has agreed with the System Operator to include the 33 kV busbar voltage measurements into the System Operation SCADA system, and has transferred it the responsibility of maintaining the voltage in this busbar within the above mentioned limits.

3.3.3. In order to maintain the voltage within permissible limits, in the Transmission Network, the System Operator shall use all the available means under its direct control. Among them:

(a) **Generating Units:** Instruct the CDGUs the voltage to be maintained at the Connection Point, producing or absorbing reactive power, within the operational limits established for these units.

(b) **Transmission Equipments:** Directly operate (connect or disconnect) reactors or capacitors in the transmission network or instruct the Transmission Licensee to perform such operations.

(c) **Transmission Transformers:** Directly operate Transmission Transformers on load tap changers, or instruct the Transmission Licensee to perform such operations.

(d) **Distribution Network:** Control the power factor (or reactive demand) at the Connection Points in order assure the active and reactive demand is within the limits stated in the Connection Agreement.

Voltage Control in the Transmission Network

3.3.4. Voltages in the Transmission Network shall be kept within the above indicated limits at least:

(a) 95% of the time in any calendar month

(b) 97 % of the time in any calendar year

3.3.5. Voltages in the Transmission Network shall be kept within limits stated in the Grid Code under “System Stress Conditions” at least 99% of the time in any calendar year.

3.3.6. Voltage control compliance will be assessed through a continued measurement and recording of the voltage at selected Control Buses.

3.3.7. Within six (6) months following the approval of this Performance Standards or granting the System Operator a license which includes Performance Indicators in accordance with this System Operator Performance Standards, the System Operator shall submit to the EMRC for approval a group of 400, 220 and 132 kV buses, which will be considered as Control Buses. The System Operator will choose and propose the Control Buses in order to be representative of the voltages levels across the whole Transmission System, and can not be buses of Substations where CDGUs where connected.

3.3.8. Initially proposed Control Buses shall not be less than:

(a) 3 in 400 kV

(b) 10 in 132 kV

3.3.9. Every year, before November 30th, the System Operator will propose to the EMRC for approval a new set of Control Buses, which will be used in monitoring voltage compliance within the next calendar year. The EMRC will have the right to propose specific points in the transmission network to be used as Control Buses and the System Operator shall include them in their proposal, unless measurement of their voltages have not been incorporated into the SCADA system, and it will not be feasible to introduce them within the following 6 (six) months.

3.3.10. The EMRC will have the right to increase the minimum number of Control Buses stated in Condition 3.3.8. from time to time.

3.3.11. Within the following 30 (thirty) days of the EMRC approval of the proposed Control Buses, the System Operator shall make all necessary arrangements to assure that:

(a) A sample (measurement) of the voltage of each Control Bus is obtained by the SCADA system, at least once every 2 minutes.

(b) These samples, with its associated name, date and time tag, will be registered, saved and stored separately from other stored SCADA values, by the System Operator information system.

The System Operator shall keep these registers, at least during 3 (three) calendar years for auditing proposes.

3.3.12. The System Operator shall produce periodic statistical analysis of the stored data (at least once a month) in order to assure the voltages in the Control Buses are within the limits specified in 3.3.4 and 3.3.5. and to produce the monthly and yearly reports indicated in Monitoring and Control section of this Performance Standards.

3.3.13. When performing the above mentioned statistical analysis and reports, following registers will be excluded:

(a) All the registers corresponding to the buses and periods in which the System Operator has informed the EMRC, in its DAGS Resume Report, it will be unable to comply with the voltage limits indicated in 3.3.4. and 3.3.5 in specific buses, due to generation unavailability and/or lack of voltage control resources (only for the specific periods indicated in the mentioned report).

(b) All the registers corresponding to the buses and periods in which the System Operator have declared to be unable to comply with the voltage limits indicated in 3.3.4. and 3.3.5. in specific buses, due to:

(i) Generation or Network Equipment Outages, only in the cases these Outages occurred after the DAGS Resume Report has been issued.

(ii) Rejection of the Generation, Transmission or Distribution Licensees to follow the instructions sent by the System Operator, or under-performance of the equipments controlled by other licensees.

(iii) Active or reactive demand in a Bulk Supply Point above the maximum demand stated in the corresponding Connection Agreement.

The situations listed in (i), (ii) and (iii) above, need to be registered in the Operation Book, and communicated to the EMRC in the Actual Operation Resume Report.

Voltage Control at 33 kV Bulk Supply Points

3.3.14. The Transmission Licensee and the System Operator shall agree with the Distributors and the Principal Consumers the voltage profile to be maintained at the Connection Points. This voltage profile may specify different values for voltage in different periods of the year and/or at different hours during the day. The agreement shall also specify a voltage band around the targeted value. The agreement will form part of the Operation Agreement. Copies of it shall be sent to the EMRC.

3.3.15. Provided the load at the Connection Point does not exceed the Maximum Connection Capacity stated in the Operation Agreement, the System Operator shall maintain the voltage at the Connection Point inside the agreed voltage band at least during 97 % of the time. It will also use its best endeavours to maintain the voltage as close as possible to the targeted value during Normal Operation.

3.3.16. Compliance with the above mentioned obligation will be assessed through a continued measurement and recording of the voltage at selected 33 kV buses.

3.3.17. Every three months, the EMRC will communicate the System Operator the 33 kV buses which will be used in monitoring compliance with voltage limits at the Bulk Supply Points. Within the following 30 (thirty) days of this communication the System Operator shall make all necessary arrangements to assure that:

(a) A sample (measurement) of the voltage of each Control Bus is obtained by the SCADA system, at least once every 2 minutes.

(b) These samples, whit its associated name, date and time tag, will be registered, saved and stored separately from other stored SCADA values, by the information system.

The System Operator shall keep these registers, at least during 3 (three) calendar years for auditing proposes.

3.3.18. If the System Operator is unable to comply with the provisions indicated in 3.3.17 in one or more Bulk Supply Point, due to limitations imposed by its SCADA system (information of the Bulk Supply Point not incorporated into the SCADA system), it will communicate the situation to the EMRC within the first 15 (fifteen) days of receiving the EMRC notification, with adequate supporting information. The EMRC may propose other Bulk Supply Points as replacement.

3.3.19. The System Operator shall statistically analyse stored data in order to assure the voltages in the Control Buses are within the limits specified in 3.3.15. and to produce the monthly and yearly reports indicated in Monitoring and Control section of this Performance Standards.

3.3.20. When performing the above mentioned statistical analysis and reports, following registers will be excluded:

(a) All the registers corresponding to the buses and periods in which the System Operator has informed the EMRC it will be unable to comply with the voltage limits indicated in 3.3.15. due to lack of adequate voltage control equipments.

(b) All the registers corresponding to the buses and periods in which the System Operator have declared to be unable to comply with the voltage limits indicated in 3.3.15. due to an active or reactive demand in a Bulk Supply Point above the maximum demand stated in the corresponding Connection Agreement. This situations need to be registered in the Operation Book, and communicated to the EMRC in the Actual Operation Resume Report.

3.4. FLOWS CONTROL

3.4.1. The System Operator shall permanently monitor and control the flows in all Transmission Equipment, while performing Real Time operation, in order to assure no Operational and/or Nominal Limit is exceeded in Normal Conditions.

3.4.2. Transmission Equipments will be divided into two different categories:

(a) Tie Lines and other 400 kV Transmission Lines

(b) Other Transmission Equipments.

The System Operator in coordination with the Transmission Licensee may decide to include within the first group any other Transmission Equipment which may severely impact in the safety, security or reliability of the system. The EMRC may request the System Operator to incorporate within the first group other Transmission Equipments, provided enough flow information in this Transmission Equipment is incorporated in the SCADA system.

3.4.3. The Performance Indicators that will measure compliance with Transmission Equipment flow monitoring and control will be the relative time the flow in these equipments are inside the limits indicated below.

3.4.4. Flow in the Tie Lines and the 400 kV Transmission Lines shall be:

(a) During Normal or Alarm Conditions:

(i) 98% of the time inside its Operational Limit, in any calendar month

(ii) 99% of the time inside its Operational Limit during the calendar year.

(b) Under Emergency Conditions:

(i) 99.9 % of the time inside its Stress Limits in any calendar month.

3.4.5. Flow in other Transmission Equipments shall be:

(a) During Normal or Alarm Conditions:

(i) 95% of the time inside its Operational Limit, in any calendar month.

(ii) 97% of the time inside its Operational Limit, during the calendar year.

(b) Under Emergency Conditions:

(i) 99 % of the time inside its Stress Limits in any calendar month

3.4.6. Before the end of Phase 1, the EMRC will issue a directive, indicating the way compliance with the above mentioned tolerances will be monitored.

3.5. LOAD SHEDDING

3.5.1. Incidents that occur in the network may produce drops in the frequency of the system. This drop of the frequency must be corrected as fast as possible, since may lead to equipment damage or to a full or partial blackout. In order to prevent excessive drop of the frequency an automatic load shedding shall take place, in accordance with the indication and procedures stated in the Demand Control Plan and the Defence Plan.

3.5.2. After any incident that implied the automatic Load Shedding Scheme operates, or it was expected to operate, the System Operator shall send to the EMRC a report containing at least:

(a) A description and analysis of the incident.

(b) The performance of the Primary Regulation and the Primary Reserve.

(c) A comparison between the Load actually shed, and what was expected to be shed, according with the Demand Control Plan and the Defence Plan.

(d) An analysis of the performance of the load shedding scheme, indicating the actual response of the Users.

(e) Clear indication if one or more of the Generation, Transmission or Distribution Licensees, or a Principal Consumer fail to perform according with the indications stated in the Demand Control or the Defence Plan.

(f) The adequacy of the of the Load Shedding Scheme indicated in the Demand Control Plan and the Defence Plan.

(g) Proposed remedial actions and an action plan to correct the situation, including immediate and medium term actions), in the cases the Demand Control Plan and/or the Defence Plan are judged inadequate; or any User fails to adequately perform, and the expected improvements.

3.6. SYSTEM RESTORATION

3.6.1. The Performance Indicator that will measure System Operator performance in system restoration will be the time required to reconnect all disconnected loads following an incident that affects more than 5% of the total connected Load.

3.6.2. Since all incidents are of different nature, all restorations processes will be also different. Therefore, no specific targets will be imposed to the above mentioned indicator.

3.6.3. The System Operator shall monitor the time used to restore the total load in all those incidents that affect a more than 5% of the total connected Load existing before the incident starts.

3.6.4. After each one of these incidents, the System Operator shall produce and send to the EMRC a written report containing at least:

(a) The cause or causes of the incident

(b) The development of the incident

(c) The executed restoration process

(d) The time required to restore

(i) 25% of the disconnected load.

(ii) 50% of the disconnected load.

(iii) 95% of the disconnected load.

(e) The lessons learnt and the proposed actions to correct possible inefficiencies detected.

3.6.5. The EMRC will review the above mentioned System Operator report, require details or clarifications as consider necessary, and may issue recommendations to the System Operator and/or other Users, in order to prevent similar incidents in the future, and/or correct potential inefficiencies in the restoration process.

3.7. ACTUAL OPERATION RESULTS

3.7.1. Based on the information collected by the SCADA and metering system and other relevant information collected from Distribution Licensees and Principal Consumers, the

System Operator will prepare, and submit to the Bulk Supply Licensee, an operational report: The Bulk Supply Actual Generation Schedule (BS-AGS report).

3.7.2. The BS-AGS will be sent to the Bulk Supply Licensee every day, before 10:00 a.m., and will cover the period from 00:00 a.m. to 12:00 p.m. of the previous day. The BS-AGS shall contain all relevant information that it is required by the Bulk Supply Licensee to calculate the total cost associated with the actual system operation the previous day. The System Operator is obliged to keep copies of the BS-AGS Reports during at least three (3) calendar years.

3.7.3. Not later than Thursday 2:00 p.m. every day, the Bulk Supply Licensee will communicate the System Operator the total cost associated with the operation of the previous day. Once this information will be received, the System Operator will prepare an Actual Operation of the System Resume Report (AOS Resume Report) that shall be send to the EMRC not later than 3:00 p.m. every day, according with the formats described below (Monitoring and Control Section).

4. SECTION: MONITORING AND CONTROL

4.1. CONTROL PHASES

4.1.1. The implementation of the Performance Indicators and this System Operation Performance Standards shall be done in two consecutive Control Phases.

4.1.2. The first Control Phase shall be called Control Phase 1 or adaptation Control Phase, and it will have a duration of twelve (12) months, after the EMRC approval of this System Operation Performance Standards or the granting of a system operation licence that includes Performance Indicators in accordance with this System Operation Performance Standards.

4.1.3. During Control Phase 1 the System Operation Licensee will have the following obligations:

(a) Every working day, following the first 3 (three) months from approval and issuing of this Performance Standards:

(i) Submit to the EMRC, in the format indicated in Annex 5, the Day Ahead Generation Schedule Resume Report (DAGS Resume Report) corresponding to the expected operation of the following day (or the following days before a non working day or holiday)

(ii) Submit to the EMRC, in the format indicated in Annex 5, the Actual Operation of the System Resume Report (AOS Resume Report) corresponding to the actual operation of the previous day (or the previous days after a non working day or holiday)

(b) Every week, following the first 3 (three) months from approval and issuing of this Performance Standards:

(i) Submit to the EMRC, in the format indicated in Annex 5, the Week Ahead Generation Schedule Resume Report (WAGS Resume Report) corresponding to the expected operation of the following week.

(c) Within the first 6 (six) month from the approval and issuing of this Performance Standards:

(i) To agree with the Generation Licensees, and to submit to the EMRC for approval, the templates and formats to be used to communicate the weekly Indicative Running Notifications and the Daily Indicative Running Notifications.

(ii) To agree with the Bulk Supply Licensee, and to submit to the EMRC for approval, the templates and formats to be used to communicate the Bulk Supply Week Ahead Generation Schedule (BS-WAGS) report, the Bulk Supply Day Ahead Generation Schedule (BS-DAGS) report and the Bulk Supply Actual Generation Schedule (BS-AGS) report.

(iii) To develop and submit to the EMRC for approval, the Minimum Security Criteria that will be used to conduct the week and day ahead dispatch, the operational studies and real time operation.

(d) Within the first 9 (nine) month from the approval and issuing of this Performance Standards:

(i) To agree with the involved Users, and submit to the EMRC for approval, a Restoration Plan with the contents indicated in the Grid Code.

(ii) To develop and submit to the EMRC for approval, the Defense Plan.

(iii) To develop and submit to the EMRC for approval, the Demand Control Guidelines and the Demand Control Plan.

(e) Develop, organise and maintain the data bases and information systems to properly calculate all the Performance Indicators defined in this Performance Standards.

4.1.4. The Second Control Phase shall be called Control Phase 2, it will begin at the end of Control Phase 1, and will last until 6 (six) months following the moment the Jordanian power system starts to operate under AGC control, and all required modifications in selected CDGUs have been completed.

4.1.5. Upon a specific request by the System Operation Licensee, the EMRC will have the right to extend the duration of Control Phase 1. The System Operation Licensee shall raise the request for that extension at least 3 months in advance to the starting of Second Control Phase with adequate supporting documentation that proves its impossibility to comply with the obligations stated in this Performance Standards and its endeavour to adapt itself to the requirements imposed.

4.1.6. During this period, the System Operation Licensee will have the following obligations (in addition to those stated for Phase 1):

(a) Calculate and send to the EMRC all the Performance Indicators as defined and established in this System Operator Performance Standards, with the exception of Secondary Reserve Performance Indicators.

(b) Plan and operate the Electric System in order to comply with the Performance Indicators within the tolerances approved by the EMRC.

4.1.7. The Final Control Phase will begin at the end of Control Phase 2.

4.1.8. During this phase, the System Operation Licensee will have the following obligations (in addition to those stated for Phase 1 and 2):

(a) Calculate and send to the EMRC the Secondary Reserve Performance Indicators as defined and established in this System Operator Performance Standards.

(b) Plan and operate the Electric System in order to comply with the Secondary Reserve Performance Indicators within the tolerances approved by the EMRC.

4.2. INFORMATION SYSTEM, MONITORING AND CONTROL

4.2.1. Before the end of Control Phase 1, the System Operation Licensee shall prepare and submit a report to the EMRC for approval, containing adequate documentation regarding the data bases and information systems implemented in order to gather, process, analyze and store all the information required to assess compliance with this Performance Standards and to calculate Performance Indicators in accordance with this System Operation Performance Standards.

4.2.2. The EMRC will have the right and the System Operator Licensee shall allow the EMRC or its authorised representatives to inspect and revise the data bases and information system defined in 4.2.1 of this System Operation Performance Standards, in order for the EMRC to audit the process, data and the accuracy of the information submitted periodically by the System Operation Licensee to the EMRC. The EMRC will have the right to hire qualified companies or persons to perform this activity on its behalf.

4.2.3. During Control Phase 2 and Final Phase, with the purpose of carrying out suitable control and monitoring of the obligations regarding Operational Planning and the associated Performance Indicators, the System Operator Licensee shall submit to the EMRC, in a suitable organized manner or in such format as the EMRC may establish the following monthly information:

(a) Demand Forecast Performance Indicators, as calculated until that month of the calendar year, as established in this Performance Standards

(b) Histograms showing the statistical distribution of WAFRE and DAFRE values, until that month of the calendar year, as established in this Performance Standards.

(c) Generation Scheduling Performance Indicators, as calculated until that month of the calendar year, as established in this Performance Standards

(d) Histograms showing the statistical distribution of $MAPD_{WA}$ and $MAPD_{DA}$ values, until that month of the calendar year, as established in this Performance Standards.

(e) Frequency Performance Indicators, when operating isolated from LEJSL System, as calculated until that month of the calendar year, as established in this Performance Standards

(f) Histograms showing the statistical distribution of the frequency values, until that month of the calendar year, as established in this Performance Standards. Frequency histograms shall be produced separately for Operation isolated from the LEJSL System and operation interconnected with the LEJSL System

(g) Total Monthly Dispatch Costs (week ahead forecasted costs, day ahead forecasted costs, and actual operation costs, as calculated until that month of the calendar year, as established in this Performance Standards.

(h) Percent of time, the voltage values in the Control Buses where inside the tolerances indicated in this Performance Standards, calculated until that month of the calendar year.

(i) Histograms showing the statistical distribution of voltages values in the Control Buses, until that month of the calendar year, as established in this Performance Standards.

(j) Percent of time, the voltage values in the monitored 33 kV Bulk Supply Points where inside the tolerances indicated in this Performance Standards, calculated until that month of the calendar year.

(k) Histograms showing the statistical distribution of voltages values in monitored 33 kV Bulk Supply Points, until that month of the calendar year, as established in this Performance Standards.

(l) Percent of time, the flows in selected Transmission Circuits where inside the tolerances indicated in this Performance Standards, calculated until that month of the calendar year.

4.2.4. During Final Control Phase, in addition to the requirements indicated in Condition 4.2.3., the monthly information shall contain also:

(a) Secondary Reserve Performance Indicators, as calculated until that month of the calendar year, as established in this Performance Standards

(b) Histograms showing the statistical distribution of TBSC series, until that month of the calendar year, as established in this Performance Standards.

4.2.5. The EMRC will issue directives regarding the format in which the above mentioned information will be supplied.

4.2.6. Every year, before the end of February, the System Operator will issue an Annual Operational Report which will contain a critical analysis of the operation of the system in the previous year, along with a resume of most relevant parameters and results. Before the end of Control Phase 1, the EMRC will issue a directive indicating the minimum contents of the Annual Operational Report. Once analysed and approved by the EMRC, this report shall be published in the System Operator web page (NEPCO web page).

4.2.7. The EMRC shall have the right to request additional information as necessary to perform its monitoring and control role, and the System Operation Licensee shall allow the access to the primary documentation and/or send the necessary data as requested by the EMRC. The deadline to submit this additional information shall be not less than seven (7) Business Days from the date of receipt of the request by the System Operation Licensee.

4.3. NON COMPLIANCE WITH ESTABLISHED TOLERANCES

4.3.1. During Control Phase 1, the EMRC will not establish tolerances for the Performance Indicators.

4.3.2. During Control Phase 2 and Final Control Phase, if the System Operator fails to perform in one or more of the Performance Indicators established in this Performance Standard, not later than ninety (90) calendar days after the end of the year, the System Operation

Licensee shall submit to the EMRC for approval a detailed report with an action plan to solve or mitigate the deficiency. The report shall include, among others, the following:

(a) Analysis of the causes of the deficiencies

(b) Description of the current situation and the detected deficiency

(c) Description of the Grid Code procedures, software, information technology tools or databases which are considered inappropriate or insufficient to comply with the required tolerances (in the case of non compliance with Operational Planning Performance Indicators)

(d) Description of electrical equipment or other licensee performance which contribute in a large extent to the non-compliance (in the case of non compliance with real time Operation Performance Indicators)

(e) Remedial actions to correct the situation, including immediate and medium term actions) and expected improvements

(f) Detailed work-plan with the proposed actions and required investments,

4.3.3. When the System Operation Licensee submits a report in accordance to the previous paragraph, the EMRC will review the proposed plan and may request clarifications or modifications prior to approval. Once approved, the plan will be binding to the System Operation Licensee and the EMRC shall have the right to monitor and audit its effective execution. During the plan, for the implementation of the remedial actions, the EMRC will have the right to exempt the System Operation Licensee from compliance with the affected Performance Indicators, and/or to modify the tolerances in accordance with the approved plan.

5. SECTION: NON COMPLIANCE

5.1. DEFINITION

5.1.1. If the System Operation Licensee fails to fulfil all the provisions established in this Performance Standard, it shall be considered a Non Compliance situation.

5.1.2. A Non Compliance situation will include (but not be limited to):

(a) Failure to provide the EMRC, on time, with all the information established in this System Operation Performance Standards

(b) Providing the EMRC incomplete or inaccurate data or reports, in particular inaccuracies or other problems verified during the Annual Operational Audit or during periodic EMRC audits on the information submitted by the System Operation Licensee.

(c) Failure to implement in time the procedures and information systems established in this Performance Standard

(d) Failure or unsuitable delays in the execution of the approved remedial actions and plans to improve system operation quality

5.2. PENALTIES

5.2.1. If the System Operation Licensee is in a Non Compliance situation, the EMRC can apply penalties, according to Article 40 of the General Electricity Law and consider the situation a non-compliance with its licence conditions.

ANNEX 1: CALCULATION OF LOAD FORECAST PERFORMANCE INDICATORS

1. ELABORATION OF THE TIME SERIES

In order to calculate the Load Forecast Performance Indicators, 3 time series need to be formed:

- **Actual Demand series (AD)**: It is a time series of registers corresponding to the actual hourly Gross Demand values of the reporting period. Each value will be calculated as the addition of Net Generation + Net Interchange, using the information provided by the SCADA system. This time series should be corrected in order to take into account network incidents that implied non supplied energy.

- **Day ahead forecast series (DF)**: It is a time series of registers corresponding to the values of the hourly forecasted demand the day ahead (DADF), as indicated in condition 2.1.3, for the reporting period

- **Week ahead forecast series (WF)**: It is a time series of registers corresponding to the values of the daily energy forecasted demand the weak ahead (WADF), as indicated in condition 2.1.2, for the reporting period

Using the above mentioned series, the System Operator will construct four hourly time series, with the absolute and relative errors in the forecasts:

- **Day Ahead Demand Forecast Absolute Error series (DAFAE)**: It is the series of absolute errors (without sign), in MW, of each hourly demand value forecasted the day ahead.

  $$DAFAE_i = |DF_i - AD_i|$$

- **Week Ahead Demand Forecast Absolute Error series (WAFAE)**: It is the series of absolute errors (without sign), in MWh, of each daily energy demand value forecasted the week ahead.

  $$WAFAE_i = |WF_i - TE_i|$$

  TE_i = Total energy demand of day i

- **Day Ahead Demand Forecast Relative Error series (DAFRE)**: It is the series of relative errors (without sign), in %, of each hourly demand value forecasted the day ahead.

  $$DAFRE_i = \frac{|DF_i - AD_i|}{AD_i}$$

- **Week Ahead Demand Forecast Relative Error series (WAFRE)**: It is the series of relative errors (without sign), in %, of each hourly demand value forecasted the week ahead.

$$WAFRE_i = \frac{|WF_i - TE_i|}{TE_i}$$

2. FORECAST QUALITY METRICS CALCULATION

(a) MAE_{DF} will be calculated as:

$$MAE_{DF} = \frac{\sum_{i=1}^{NV} DAFAE_i}{NV}$$

DAFAEi: Individual values of the Day Ahead Demand Forecast Absolute Error series

NV: Total number of registers in the reporting period (24 * nº of days in the reporting period)

(b) MAE_{WF} will be calculated as:

$$MAE_{WF} = \frac{\sum_{i=1}^{NV} WAFAE_i}{NV}$$

WAFAEi: Individual values of the Week Ahead Demand Forecast Absolute Error series

NV: Total number of registers in the reporting period = nº of days in the reporting period

(c) $MAPE_{DF}$ will be calculated as:

$$MAPE_{DF} = \frac{\sum_{i=1}^{NV} DAFRE_i}{NV}$$

DAFREi: Individual values of the Day Ahead Demand Forecast Relative Error series

NV: Total number of registers in the reporting period (24 * nº of days in the reporting period)

(d) $MAPE_{WF}$ will be calculated as:

$$MAPE_{WF} = \frac{\sum_{i=1}^{NV} WAFRE_i}{NV}$$

WAFREi: Individual values of the Week Ahead Demand Forecast Relative Error series

NV: Total number of registers in the reporting period = nº of days in the reporting period)

(e) The procedure to calculate the $MARGIN_{DA}$ will be:

(i) Take the DAFRE time series, previously calculated and re-arrange it in ascending order (from 0 to the maximum value).

(ii) $MARGIN_{DA}$ is the relative error value, in the above mentioned series, which it is exceeded only in 10% of the NV registers.

(f) The procedure to calculate the $MARGIN_{WA}$ will be:

(i) Take the WAFRE time series, previously calculated and re-arrange it in ascending order (from 0 to the maximum value).

(ii) $MARGIN_{WA}$ is the relative error value, in the above mentioned series, which it is exceeded only in 10% of the NV registers.

ANNEX 2: CALCULATION OF GENERATION SCHEDULING PERFORMANCE INDICATORS

1. ELABORATION OF THE TIME SERIES

In order to calculate the Generation Scheduling Performance Indicators, 3 time series need to be formed:

- **Actual Cost series (AC)**: It is a time series of registers corresponding to the actual costs of the daily dispatch. Each value will be calculated with the information provided by the Bulk Supply Licensee, regarding the variable generation costs of each CDGU utilized in the dispatch and the net costs of power importation and exportations.

- **Day ahead forecasted costs series (FC_{DA})**: It is a time series of registers corresponding to the values of the daily forecasted costs in the day ahead generation scheduling (DAGS), as indicated in condition 2.2.13, for the reporting period

- **Week ahead forecasted cost series (FC_{DA})**: It is a time series of registers corresponding to the values of the daily forecasted cost in the weak ahead generation scheduling (WAGS), as indicated in condition 2.2.7, for the reporting period

Using the above mentioned series, the System Operator will construct four daily time series, with the absolute and relative differences in the cost forecasts:

- **Day Ahead Forecast Schedule Absolute Difference series (DAFSAD)**: It is the series of absolute costs differences (without sign), in JD, between the actual dispatch cost and the forecasted one when developing the Day Ahead Generation Scheduling.

  $$DAFSAD_i = \left| FC_{DAi} - AC_i \right|$$

- **Week Ahead Forecast Schedule Absolute Difference series (WAFSAD)**: It is the series of absolute costs differences (without sign), in JD, between the forecasted cost when developing the Week Ahead Generation Scheduling and the forecasted one when developing the Day Ahead Generation Scheduling.

  $$WAFSAD_i = \left| FC_{WAi} - FC_{DAi} \right|$$

- **Day Ahead Forecast Schedule Relative Difference series (DAFSRD)**: It is the series of relative costs differences (without sign), in %, between the actual dispatch cost and the forecasted one when developing the Day Ahead Generation Scheduling.

  $$DAFSRD_i = \frac{\left| FC_{DAi} - AC_i \right|}{AC_i}$$

- **Week Ahead Forecast Schedule Relative Difference series (WAFSRD)**: It is the series of relative costs differences (without sign), in %, between the forecasted cost when developing the Week Ahead Generation Scheduling and the forecasted one when developing the Day Ahead Generation Scheduling.

$$WAFSRD_i = \frac{|FC_{WAi} - FC_{DAi}|}{FC_{DAi}}$$

2. FORECAST QUALITY METRICS CALCULATION

(a) MAD_{DA} will be calculated as:

$$MAD_{DA} = \frac{\sum_{i=1}^{NV} DAFSAD_i}{NV}$$

DAFSADi: Individual values of the Day Ahead Forecasted Scheduling Absolute Difference series

NV: Total number of registers (days) in the reporting period.

(b) MAD_{WA} will be calculated as:

$$MAD_{WA} = \frac{\sum_{i=1}^{NV} WAFSAD_i}{NV}$$

WAFSADi: Individual values of the Week Ahead Forecasted Scheduling Absolute Difference series

NV: Total number of registers (days) in the reporting period.

(c) $MAPD_{DA}$ will be calculated as:

$$MAPD_{DA} = \frac{\sum_{i=1}^{NV} DAFSRD_i}{NV}$$

DAFSRDi: Individual values of the Day Ahead Forecasted Scheduling Relative Difference series

NV: Total number of registers (days) in the reporting period.

(d) $MAPD_{WA}$ will be calculated as:

$$MAPD_{WA} = \frac{\sum_{i=1}^{NV} WAFSRD_i}{NV}$$

WAFSRDi: Individual values of the Week Ahead Forecasted Scheduling Relative Difference series

NV: Total number of registers (days) in the reporting period.

ANNEX 3: CALCULATION OF SECONDARY REGULATION PERFORMANCE INDICATORS

1. ELABORATION OF THE TIME SERIES

In order to calculate the Secondary Regulation Performance Indicators, 2 series of values need to be formed:

- **ACE series**: It is a time series of registers corresponding to the actual ACE values recorded at least every 30 seconds, according with condition 3.2.3

- **TBSC series:** It is a series, calculated processing ACE series, with the values of time the ACE took to change its sign (crossing the zero value).

2. FORECAST QUALITY METRICS CALCULATION

(a) TBSCA will be calculated as:

$$TBSCA = \frac{\sum_{i=1}^{NV} TBSC_i}{NV}$$

TBSCi: Individual values of the TBSC series

NV: Total number of values of the TBSC series in the reporting period.

(b) The procedure to calculate TBSCA_95 will be:

- Take the TBSC series, previously calculated and re-arrange it in ascending order (from 0 to the maximum value).
- TBSC_95 is the value, in the above mentioned series, which it is exceeded only in 5 of the NV registers.

(c) M_TBSC is the maximum value of the TBSC series

ANNEX 4: TOLERANCES TO LOAD FORECAST, GENERATION SCHEDULING, AND SECONDARY REGULATION INDICATORS

The following tolerances will apply for the First Tariff Review period (excluding Control Phase 1), unless the EMRC, when issuing a new license to the System Operation Licensee, specifies different values for one or more of these tolerances:

1. LOAD FORECAST

The following values shall be used as tolerances for the Load Forecast Performance Indicators.

Load Forecast Performance Indicator		Value
Name	**Acronym**	
Mean Absolute Percent Error (Day Ahead Forecast)	$MAPE_{DA}$	
Mean Absolute Percent Error (Week Ahead Forecast)	$MAPE_{WA}$	
90 % Percentile of the Relative Errors (Day Ahead Forecast)	$MARGIN_{DA}$	
90 % Percentile of the Relative Errors (Week Ahead Forecast)	$MARGIN_{DA}$	

Values of MAE_{DA} y MAE_{WA} will not have tolerances. They will be registered for statistical purposes only.

2. GENERATION SCHEDULING

The following values shall be used as tolerances for the Generation Scheduling Performance Indicators.

Generation Scheduling Performance Indicator		Value
Name	**Acronym**	
Mean Absolute Percent Differences (Day Ahead Schedule)	$MAPD_{DA}$	
Mean Absolute Percent Differences (Week Ahead Schedule)	$MAPD_{WA}$	

Values of MAD_{DA} y MAD_{WA} will not have tolerances. They will be registered for statistical purposes only.

3. SECONDARY REGULATION

The following values shall be used as tolerances for the Secondary Regulation Performance Indicators.

Generation Scheduling Performance Indicator		**Value**
Name	**Acronym**	
Average Time between Sign Changes	*TBSCA*	
95 Percentile of the Time Between Sign Changes	*TBSC_95*	
Maximum Time between Sign Changes	*M_TBSC*	

ANNEX 5: FORMAT TEMPLATES FOR REPORTING

The following templates will be used by the System Operator when submitting to the EMRC the WAGS, DAGS and AOS Resume Reports.

5. 1 WEEK AHEAD GENERATION SCHEDULING RESUME REPORT

Report Date: **Week nº:**

1. CDGUs Unavailability (1):

Unit	Available output	From (2)	To (2)

(1) State in this table only those CGDUs that are expected to have a reduced availability, during at least 1 hour during the reported period

(2) Month and day. (dd/mm)

2. Transmission System Unavailability (1):

Type	Voltage	Equipment	From (2)	To (2)

(1) State in this table only those Transmission Equipments that are expected to be unavailable during at least 1 hour during the reported period

(2) Month and day. (dd/mm)

3. Energy Balance Results:

	Values in MWh						
	Saturday	**Sunday**	**Monday**	**Tuesday**	**Wednesday**	**Thursday**	**Friday**
Forecasted Load							
Comb.Cycle							
Steam Turbines							
Gas Turbines							
Diesel Turbines							
Other CDGUs							
Other non CDG							
Total Jordan Gen.							
Egypt Int.							
Syria Int.							
Total							

Unbalance (if any)							

4. Dispatch Costs Resume:

	Saturday	Sunday	Monday	Tuesday	Wednesday	Thursday	Friday
Total Cost (10^3 JD)							
Thermal cost							
Egypt Int.							
Syria Int.							
Total Cost							
Relative costs (JD/kwh)							
Thermal cost							
Egypt Int.							
Syria Int.							
Total							

5. Generation Schedule:

	Values in MWh						
	Saturday	**Sunday**	**Monday**	**Tuesday**	**Wednesday**	**Thursday**	**Friday**
Aqaba 1							
Aqaba 2							
Aqaba 3							
Aqaba 4							
Aqaba 5							
Hussein 1							
Hussein 2							
Hussein 3							
Hussein 4							
Hussein 5							
Hussein 6							
Hussein 7							
Hussein GT1							
Hussein GT2							
Rehab GT10							
Rehab GT11							
Rehab GT12							
Rehab GT13							
ASouth GT8							
ASouth GT9							
Marka GT3							
Marka GT4							

Marka GT5							
Marka GT6							
Karak GT7							
Resha 1							
Resha 1							
Resha 1							
Resha 1							
Resha 1							
Samra 1							
Samra 2							
Samra 3							
Others							
Total							

6. Ancillary Services Results:

	Values in MW						
	Saturday	**Sunday**	**Monday**	**Tuesday**	**Wednesday**	**Thursday**	**Friday**
Minimum Load							
Spinning Reserve							
Tertiary Reserve							
Maximum Morning Load							
Spinning Reserve							
Tertiary Reserve							
Maximum Evening Load							
Spinning Reserve							
Tertiary Reserve							

7. Operational Studies performed:

	Yes / No						
	Saturday	**Sunday**	**Monday**	**Tuesday**	**Wednesday**	**Thursday**	**Friday**
Load Flow							
Optimal Power Flow							
Contingency Analysis							
Stability Analysis							
Other Studies							

8. Electrical Studies Results:

	Yes / No						
	Saturday	**Sunday**	**Monday**	**Tuesday**	**Wednesday**	**Thursday**	**Friday**
Insufficient spinning reserve available?							
Insufficient non spinning reserve available?							
Voltage Control Problems Expected?							
Circuit Overload Expected?							
Stability Problems Expected?							
Other Problems Expected? (*)							

(*) Specify the expected problems in the Other Remarks Table

9. Expected System Condition:

	Put an "X" if at least during one hour during the day, the Electric System is expected to be in such Condition						
	Saturday	**Sunday**	**Monday**	**Tuesday**	**Wednesday**	**Thursday**	**Friday**
Normal Condition							
Alarm Condition							
Emergency Condition							

10. Relevant Remarks and Comments

5. 2 DAY AHEAD GENERATION SCHEDULING RESUME REPORT

Report Issuing Date: **Reported Day:**

1. CDGUs Unavailability (1):

Unit	Available output	From (2)	To (2)

(1) State in this table only those CGDUs that are expected to have a reduced availability, during at least 1 hour during the reported day

(2) Date and Time. (dd/mm hh:mm)

2. Transmission System Unavailability (1):

Type	Voltage	Equipment	From (2)	To (2)

(1) State in this table only those Transmission Equipments that are expected to be unavailable during at least 1 hour during the reported day

(2) Date and Time. (dd/mm hh:mm)

3. Day Ahead Demand Forecast (MW)

00:00 a.m.	01:00 a.m.	02:00 a.m.	03:00 a.m.	04:00 a.m.	05:00 a.m.	06:00 a.m.	07:00 a.m.

08:00 a.m.	09:00 a.m.	10:00 a.m.	11:00 a.m.	12:00 a.m.	01:00 p.m.	02:00 p.m.	03:00 pm

04:00 p.m.	05:00 p.m.	06:00 p.m.	07:00 p.m.	08:00 p.m.	09:00 p.m.	10:00 p.m.	11:00 p.m.

4. Energy Balance Results:

	Values in MWh		
	Week Ahead Forecast (1)	**Day Ahead Forecast (2)**	**Actual Operation Results**
Forecasted Load			
Combined Cycle			
Steam Turbines			
Gas Turbines			
Diesel Turbines			
Other CDGUs			
Other non CDG			
Total Jordan Gen.			
Egypt Int.			
Syria Int.			
Total			
Unbalance (if any)			

(1) State here the values that were forecasted in the Week Ahead Generation Scheduling for the day that is currently being reported.
(1) State here the most recently forecasted values for the next day

5. Dispatch Costs Resume:

	Week Ahead Forecast (1)	**Day Ahead Forecast (2)**	**Actual Operation Results**
Total Cost (10^3 JD)			
Thermal cost			
Egypt Int.			
Syria Int.			
Total Cost			
Relative costs (JD/kwh)			
Thermal cost			
Egypt Int.			
Syria Int.			
Total			

(1) State here the costs that were forecasted in the Week Ahead Generation Scheduling for the day that is currently being reported.
(2) State here the most recently forecasted costs for the next day

6. Generation Schedule:

	Day Ahead Forecast				Actual Operation Results			
	Minimum Load	**Maximum Morning Load**	**Maximum Evening Load**	**Total Energy**	**Minimum Load**	**Maximum Morning Load**	**Maximum Evening Load**	**Total Energy**
	MW	MW	MW	MWh	MW	MW	MW	MWh
Aqaba 1								
Aqaba 2								
Aqaba 3								
Aqaba 4								
Aqaba 5								
Hussein 1								
Hussein 2								
Hussein 3								
Hussein 4								
Hussein 5								
Hussein 6								
Hussein 7								
Hussein GT1								
Hussein GT2								
Rehab GT10								
Rehab GT11								
Rehab GT12								
Rehab GT13								
ASouth GT8								
ASouth GT9								
Marka GT3								
Marka GT4								
Marka GT5								
Marka GT6								
Karak GT7								
Resha 1								
Resha 1								
Resha 1								
Resha 1								
Resha 1								
Samra 1								
Samra 2								
Samra 3								
Others								
Total								

7. Ancillary Services Results:

	Values in MW	
	Day Ahead Forecast	**Actual Operation Results**
Minimum Load		
Spinning Reserve		
Tertiary Reserve		
Maximum Morning Load		
Spinning Reserve		
Tertiary Reserve		
Maximum Evening Load		
Spinning Reserve		
Tertiary Reserve		

8. Operational Studies performed:

	Yes / No		
	Minimum Load	**Maximum Morning Load**	**Maximum Evening Load**
Load Flow			
Optimal Power Flow			
Contingency Analysis			
Stability Analysis			
Other Studies			

9. Electrical Studies Results:

	Minimum Load	Maximum Morning Load	Maximum Evening Load
Load shedding or Demand Control? (1)			
Insufficient spinning reserve available?			
Insufficient non spinning reserve available?			
Voltage Control Problems Expected?			
Circuit Overload Expected?			
Stability Problems Expected?			
Other Problems Expected? (2)			

(1) If “yes” in any column complete Table 11.
(2) Specify the expected problems in the Other Remarks Table

10. Expected System Condition:

	Put an "X" if at least during half hour during the indicated period, the Electric System is expected to be in such Condition			
	00:00 a.m. – 07:00 a.m.	07:00 a.m. – 01:00 p.m.	01:00 p.m. – 06:00 p.m.	06:00 p.m. – 12:00 p.m.
Normal Condition				
Alarm Condition				
Emergency Condition				

11. Demand Reduction or Load Shedding (MW)

	00:00 a.m.	01:00 a.m.	02:00 a.m.	03:00 a.m.	04:00 a.m.	05:00 a.m.
Load Shedding						
Demand Reduction (*)						

	06:00 a.m.	07:00 a.m.	08:00 a.m.	09:00 a.m.	10:00 a.m.	11:00 a.m.
Load Shedding						
Demand Reduction (*)						

	12:00 a.m.	01:00 p.m.	02:00 p.m.	03:00 p.m.	04:00 p.m.	05:00 p.m.
Load Shedding						
Demand Reduction (*)						

	06:00 p.m.	07:00 p.m.	08:00 p.m.	09:00 p.m.	10:00 p.m.	11:00 p.m.
Load Shedding						
Demand Reduction (*)						

(*) Other means of Demand Reduction other than Load Shedding (either voluntary or imposed)

12. Expected Secondary Regulation Control

☐ Manual Control Automatic Control

- ☐ Frequency Control
- ☐ TLC Control
- ☐ FLC Control

13. Relevant Remarks and Comments

5.3 ACTUAL OPERATION OF THE SYSTEM RESUME REPORT

Report Issuing Date: **Reported day:**

1. CDGUs Unavailability (1):

Unit	Available output	From (2)	To (2)

(1) State in this table all the CGDUs that had a reduced availability during any period of the reported day

(2) Date and Time. (dd/mm hh:mm)

2. Transmission System Unavailability (1):

Type	Voltage	Equipment	From (2)	To (2)

(1) State in this table only all the Transmission Equipments that have been unavailable during any period of the reported day

(2) Date and Time. (dd/mm hh:mm)

3. Actual Registered Demand (MW)

00:00 a.m.	01:00 a.m.	02:00 a.m.	03:00 a.m.	04:00 a.m.	05:00 a.m.	06:00 a.m.	07:00 a.m.

08:00 a.m.	09:00 a.m.	10:00 a.m.	11:00 a.m.	12:00 a.m.	01:00 p.m.	02:00 p.m.	03:00 pm

04:00 p.m.	05:00 p.m.	06:00 p.m.	07:00 p.m.	08:00 p.m.	09:00 p.m.	10:00 p.m.	11:00 p.m.

4. Energy Balance Results:

	Values in MWh		
	Week Ahead Forecast (1)	**Day Ahead Forecast (2)**	**Actual Operation Results (3)**
Forecasted Load			
Combined Cycle			
Steam Turbines			
Gas Turbines			
Diesel Turbines			
Other CDGUs			
Other non CDG			
Total Jordan Gen.			
Egypt Int.			
Syria Int.			
Total			
Unbalance (if any)			

(1) State here the values that were forecasted in the Week Ahead Generation Scheduling for the day that is currently being reported.

(2) State here the values that were forecasted in the Day Ahead Generation Scheduling for the day that is currently being reported.
(3) State here the actual values for the reported day

5. Dispatch Costs Resume:

	Week Ahead Forecast (1)	**Day Ahead Forecast (2)**	**Actual Operation Results (3)**
Total Cost (10^3 JD)			
Thermal cost			
Egypt Int.			
Syria Int.			
Total Cost			
Relative costs (JD/kwh)			
Thermal cost			
Egypt Int.			
Syria Int.			
Total			

(1) State here the costs that were forecasted in the Week Ahead Generation Scheduling for the day that is currently being reported.

(2) State here the costs that were forecasted in the Day Ahead Generation Scheduling for the day that is currently being reported.
(3) State here the actual costs for the reported day

6. Generation Schedule:

	Day Ahead Forecast (1)				Actual Operation Results (2)			
	Minimum Load	**Maximum Morning Load**	**Maximum Evening Load**	**Total Energy**	**Minimum Load**	**Maximum Morning Load**	**Maximum Evening Load**	**Total Energy**
	MW	MW	MW	MWh	MW	MW	MW	MWh
Aqaba 1								
Aqaba 2								
Aqaba 3								
Aqaba 4								
Aqaba 5								
Hussein 1								
Hussein 2								
Hussein 3								
Hussein 4								
Hussein 5								
Hussein 6								
Hussein 7								
Hussein GT1								
Hussein GT2								
Rehab GT10								
Rehab GT11								
Rehab GT12								
Rehab GT13								
ASouth GT8								
ASouth GT9								
Marka GT3								
Marka GT4								
Marka GT5								
Marka GT6								
Karak GT7								
Resha 1								
Resha 1								
Resha 1								
Resha 1								
Resha 1								
Samra 1								
Samra 2								
Samra 3								
Others								
Total								

(1) State here the values that were forecasted in the Day Ahead Generation Scheduling for the day that is currently being reported.
(2) State here the actual values for the reported day

7. Ancillary Services Results:

	Values in MW	
	Day Ahead Forecast (1)	**Actual Operation Results (2)**
Minimum Load		
Spinning Reserve		
Tertiary Reserve		
Maximum Morning Load		
Spinning Reserve		
Tertiary Reserve		
Maximum Evening Load		
Spinning Reserve		
Tertiary Reserve		

(1) State here the values that were forecasted in the Day Ahead Generation Scheduling for the day that is currently being reported.
(2) State here the actual values for the reported day

8. Electric System Condition:

	Put an "X" if during the indicated period, the Electric System has been in such Condition			
	00:00 a.m. – 07:00 a.m.	07:00 a.m. – 01:00 p.m.	01:00 p.m. – 06:00 p.m.	06:00 p.m. – 12:00 p.m.
Normal Condition				
Alarm Condition				
Emergency Condition				

9. Actual Demand Reduction or Load Shedding (MW)

	00:00 a.m.	01:00 a.m.	02:00 a.m.	03:00 a.m.	04:00 a.m.	05:00 a.m.
Load Shedding						
Demand Reduction (*)						

	06:00 a.m.	07:00 a.m.	08:00 a.m.	09:00 a.m.	10:00 a.m.	11:00 a.m.
Load Shedding						
Demand Reduction (*)						

	12:00 a.m.	01:00 p.m.	02:00 p.m.	03:00 p.m.	04:00 p.m.	05:00 p.m.
Load Shedding						
Demand Reduction (*)						

	06:00 p.m.	07:00 p.m.	08:00 p.m.	09:00 p.m.	10:00 p.m.	11:00 p.m.
Load Shedding						
Demand Reduction (*)						

(*) Other means of Demand Reduction other than Load Shedding (either voluntary or imposed)

10. Actual Secondary Regulation Control

☐ Manual Control Automatic Control

- ☐ Frequency Control
- ☐ TLC Control
- ☐ FLC Control

10. Relevant Remarks and Comments