Economic Policy Reform and Competitiveness Project

Market Design

April 2005
Ulaanbaatar, Mongolia

This publication was produced for review by the United States Agency for International Development. The views expressed in this publication do not necessarily reflect the views of the United States Agency for International Development or the United States Government.

Project: Mongolia Economic Policy Reform and Competitiveness Project (EPRC)
Report Title: ***Market Design***
Main Author: Michael Bekker
Contract No. 438-C-00-03-00021-00
Submitted by: EPRC Project/Chemonics International Inc., Tavan Bogd Plaza, Second Floor, Eronhii Said Amar Street. Sukhbaatar District, Ulaanbaatar, Mongolia
Telephone and fax: (976) 11 32 13 75 Fax: (976) 11 32 78 25
Contact: Fernando Bertoli, Chief of Party
E-mail address: fbertoli@eprc-chemonics.biz

ABBREVIATIONS AND ACRONYMS

AGC	Automatic Generation Control
AMR	Automatic Meter Reading
CES	Central Energy System
CHP	Combined Heat Plant
CMS	Cash Management System
EES	Eastern Energy System
EMS	Energy Management System
EPRC	Economic Policy Reform and Competitiveness Project
ERA	Energy Regulatory Authority
GoM	Government of Mongolia
HOL	High Operating Limit
ISO	Independent System Operator
JSC	Joint Stock Company
LTC	Load Tap Changer
MVAR	Mega Volt Amper Reactive
MW	Mega Watt
MWHR	Mega Watt Hours
MZBA	Main Zero Balance Account
NDC	National Dispatch Center
SCADA	Supervisory Control and Data Acquisition
SO	System Operator
STTA	Short-term Technical Assistance
UESR	United Energy System of Russia
UPS	Un-interruptible Power Supply
WES	Western Energy System
WPM	Wholesale Power Market

TABLE OF CONTENTS

ABBREVIATIONS AND ACRONYMS i
TABLE OF CONTENTS i
SECTION I: INTERNATIONAL BEST PRACTICES AND LESSONS LEARNED FROM TRANSITION TO OPEN COMPETITIVE WHOLESALE POWER MARKETS 1
SECTION II: EVALUATION OF THE FUNCTIONING OF CURRENT "SINGLE BUYER" WHOLESALE ELECTRICITY MARKET IN MONGOLIA 13
1. Background 13
2. The "Single Buyer Market" model – description and assessment of its efficiency 14
3. Conclusion and recommendation 16
SECTION III: EVALUATION OF THE NDC's TECHNICAL CAPACITY TO PERFORM THE FUNTION OF THE INDEPENDENT MARKET OPERATOR 19
1. Introduction 19
2. General description of NDC responsibilities 19
3. NDC's responsibilities as a Market Operator 19
4. Assessment of NDC's ability to act as a Market Operator 20
5. Conclusion and recommendation 21
SECTION IV: CONCEPTUAL DESIGN OF MONGOLIAN WHOLESALE POWER MARKET 25
SECTION V: RULES FOR THE WHOLESALE POWER MARKET OF MONGOLIA NATIONAL POWER SYSTEM 31
1. Introduction and market rules 31
2. The system of the wholesale bilateral contracts 34
3. Wholesale Power Market's management structure 35
4. The duties of the System Operator 36
5. Market arrangements for purchase/sale of electric energy and capacity 38
6. Monthly adjustments to annual bilateral contracts 41
7. Transmission constrains and transmission losses 42
8. Planning of power system operating regimes 43
9. The System Operator daily activities in market operation 47
10. Ancillary technological services 50
11. Market related information 51
12. Force majeure 53
SECTION VI: OPERATIONAL PROCEDURES FOR MARKET IMPLEMENTATION 59
1. *Operating procedure No.1:* Operating responsibility and authority of the System Operator 59
2. *Operating procedure No.2:* Maintenance of communications, computers, and metering equipment 63
3. *Operating procedure No.3:* Transmission maintenance scheduling for facilities operating at 110kV and above 66
4. *Operating procedure No.4:* Action during capacity deficiency 68
5. *Operating procedure No.5:* Generation maintenance and outage scheduling 69
6. *Operating procedure No.6:* Power system restoration 74
7. *Operating procedure No.7:* Actions in an emergency 79
8. *Operating procedure No.8:* Operating reserve 82

9. *Operating procedures No.9:* Scheduling and dispatching of external contracts.....84
SECTION VII: ASSESSMENT OF NDC READINESS TO FUNCTION AS A SYSTEM OPERATOR AND PRELIMINARY SCHEDULE AND COST ESTIMATE OF MARKET IMPLEMENTATION.....87
1. Introduction.....87
2. Overview of Mongolian Power System.....88
3. Description of the proposed Electricity Market responsibilities of the SO.....88
4. Description and status of NDC projects.....91
5. Assessment of NDC Readiness to perform SO function.....93
6. Additional technical and training requirements.....95
7. Cost estimate and implementation schedule.....97
ANNEX A: REGISTERED CHARACTERISTICS OF MARKET PARTICIPANTS' EQUIPMENT.....**Error! Bookmark not defined.**
ANNEX B: PROCEDURE FOR CALCULATION OF AVAILABILITY FACTORS FOR GENERATING UNITS.....**Error! Bookmark not defined.**

SECTION I: INTERNATIONAL BEST PRACTICES AND LESSONS LEARNED FROM TRANSITION TO OPEN COMPETITIVE WHOLESALE POWER MARKETS

USAID FROM THE AMERICAN PEOPLE

Economic Policy Reform and Competitiveness Project

International Best Practices and Lessons learned from transition to open competitive wholesale power markets

Presented to Mongolia Power Sector Participants

by Michael Bekker

Ulaanbaatar, Mongolia

January 16, 2006

USAID FROM THE AMERICAN PEOPLE

Economic Policy Reform and Competitiveness Project

Outline of presentation

- Moving forces and conditions needed to facilitate transition to competition
- From regulation to competition
- Role of the System Operator
- Market structure and market rules
- Stakeholders and their role
- Market monitoring
- Retail Competition
- Role of the regulator in a competitive market
- Some observations on emerging markets
- Prospects for a competitive power market in a context of the power system of Mongolia

Moving Forces for Transition to Competitive Markets

- Large industrial consumers in areas with high electricity prices felt trapped by their electric utilities and wanted an opportunity to select their suppliers
- Independent Power Producers wanted to have an equal opportunity to compete with electric utilities generation
- Desire of public policy makers to introduce the retail competition and an opportunity to choose a supplier to all end users
- Willingness on the part of top managers of vertically integrated utilities to divest generating assets due to the increased risk of operating generating assets

1

Measures to facilitate transition to competitive markets

- Changes in electricity policy to:
  - Clarify electric utilities rights and obligations
  - Provide an equal and non-discriminatory access to the transmission network
  - Implement a code of conduct changes to assure functional separation of regulatory and competitive market related activities
- Creation of Independent System Operators (ISO)
- Development of regional transmission tariffs
- Unbundling of electric utilities tariffs
- Divestment of generating assets
- Rate of return incentives for electric utilities to join markets operated by ISOs

4

From regulation to competition

- The first and foremost goal during transition:
  - ***Reliability and security of power supply should not suffer***
- This goal is achieved by:
  - Effective interaction of system operator with market participants based on:
  - adequacy of generating resources
  - established professional relations
  - adequacy of operating procedures
  - successful experience of operation in regulatory requirements, and
  - adequacy of legal and regulatory acts, specifying responsibility for reliable system operation
- ***Lesson 1 – power systems with a long established tradition of central economic dispatch made a better transition to the competitive market, i.e.***
  - **Northeastern USA (PJM, New York, New England) vs California**

5

From regulation to competition - continued

- ***Lesson 2 – the industry restructuring and unbundling of vertically integrated utilities is not an absolute requirements for transition to successful wholesale power market:***
- PJM – not all members fully divested their generation
- New England – one state did not restructure its power sector
- New York – fully restructured its power sector
- California – fully restructured its power sector

- ***Lesson 3 - successful functioning of wholesale power market requires strong Independent System Operator***

6

Role of the System Operator

- System Operator should be independent of market stakeholders
- Assumes operational control over transmission system and administers open access to the system
- Serves as a technological guarantor of the wholesale power market
- Works in close contact with market stakeholders' organization
- Has to be aware of implication of its operational decisions on business activities of market participants
- When administers the market should serve as a conduit for market transactions but not serve as a counterpart to them
- Should serve as a market monitor, periodically provide "State of the market" reports, report uncompetitive behavior to regulators
- Should operate under the tariff approved by regulators

- ***Lesson 4 – It is best when technological operation of power system and market administration is concentrated within a single organization***

7

Market Structure and Market Rules

- Market structure should provide for accommodation of legitimate needs of suppliers and consumers (sellers and buyers) while taking into account practical realities of particular power system in order to facilitate delivery of the market products from suppliers to consumers in the most efficient fashion
- The main issues to consider when select market structure:
  - type of pricing arrangements
  - single clearing price vs nodal prices
  - single settlement system vs multi-settlement system
  - one product vs multiple products (i.e. energy only vs energy and capacity)
  - how to deal with congestion and congestion fund if any
  - how to fit in ancillary services

8

Market Structure and Market Rules - continued

- Selection of the proper market structure is vital for market success
- Market rules should implement all concepts of approved market structure while being fair, reasonable and transparent
- Market rules approval should require stakeholders consent
- Once market rules are approved System Operator should implement them in transparent and nondiscriminatory fashion
- Market rules should contain procedures for dispute resolution and sanctions for non-compliance
- Market rules should contain provisions for suspension of market operation under extraordinary circumstances

9

Market Structure and Market Rules - continued

- ***Lesson 5 – Begin with the simple structure – do real time market first***
- ***Lesson 6 – Energy only markets proved to be politically and socially unacceptable due to high price volatility***
- ***Lesson 7 – Successful capacity market has yet to be developed***
- ***Lesson 8 – Bilateral contracts are necessary element of a successful market***
- ***Lesson 9 – No market rules are forever !***

10

Market stakeholders and their role

- In order to effectively participate in market related decision making process stakeholders should form an organization
- Usually stakeholders organization is structured by sectors depending on market interests (i.e. sellers, buyers, end-users, etc..)
- Each sector is allocated percentage of a vote
- Stakeholder organizations activities are often governed through committees, such as:
- Main committee
- Technical committees (i.e. market, operational reliability, tariff, budget, etc..)
- The role of stakeholder organization may be decisional or advisory

11

Market stakeholders and their role - continued

- **Lesson 10 – In markets with completely unbundled power sector and diverse stakeholders interests it is better when stakeholder organization role is advisory**

12

Market monitoring

- Market monitoring plays dual role:
- To assess efficiency and competitiveness of the market and
- To prevent and mitigate exercise of market power
- Independent market monitor is the best instrument to assess the efficiency and competitiveness of the market
- Market power mitigation is best performed by the market monitor who is the member of the System Operator's or other market administrator's staff
- May be performed ex-ante or
- Ex-post

- ***Lesson 11 – Ex-ante with an advance notification and request for explanation is a superior way to conduct mitigation***

- ***Lesson 12 – The Regulator is an ultimate market monitor***

13

Retail Competition

- Goal – to reduce prices for end-use customers by providing them with a choice of supplier
- Issues that needed to be solved:
  - Protecting customers that did not choose or weren't chosen by a retail supplier
  - Licensing and financial assurances
  - Promotion of renewable resources and "green" power
  - Technical issues associated with metering and billing
  - Relations between wholesale and retail markets

Lesson 13 – Retail competition works but not necessarily in a way it was originally intended

14

Role of the Regulator

- Prevailing opinion at the advent of restructuring was that the role of the energy regulating authorities will diminish
- In fact the role of the Regulator in the competitive market environment turned to be much more interesting and difficult than under traditional cost-of-service regulation
- Regulator is responsible for all normative acts necessary for market operation and administration
- Regulator oversees all competitive markets and their interaction with each other
- Regulator grants market based rates authority
- Regulator acts as an ultimate market monitor
- Example - to reflect these new functions staff of the USA Federal Energy Regulatory Commission (FERC) since the advent of the competitive markets increased approximately by 50%.

- ***Lesson 14 – it is not a deregulation, it is a restructuring!***

15

Some observations on emerging markets

- Russian Federation
  - Fully tariff-based market with imputed bi-lateral payments obligations before 2003, 15% open for competition thereafter
  - Spot market clears the deviations between planned schedules and real time operation utilizing elements of competitiveness
  - In April 2006 expected implementation of regulated bi-lateral contracts market with fully competitive spot market based locational marginal prices and two part settlement system – day-ahead and near real time
  - Later in the year expected introduction of installed capacity and ancillary services markets

16

Some observations on emerging markets - continued

- Ukraine:
  - Single buyer based competitive market with a single clearing price
  - No bilateral contracts allowed
  - Some distribution companies are privatized
- Georgia
  - Single buyer tariff based market
  - Bilateral contracts were allowed but not practiced
  - Some distribution companies and generators are privatized
- Armenia
  - Single buyer tariff based market with bi-lateral contracts for payments
  - Single privatized distribution company
  - Some generation is privatized

17

Some observations on emerging markets - continued

- Kazakstan
  - Competitive wholesale power market
  - Distribution and generation privatized

Regional power markets

- Central Asia
  - Functioning Regional Dispatch Center coordinates implementation of bi-lateral contracts
  - Efforts to create a regional spot market failed
- Southeastern Europe
  - Work in progress to develop regional market that includes Romania, Bulgaria, Greece, Turkey, Albania, Croatia, Bosnia & Hertzegovina

18

Observations on current situation in Mongolia

- From the electrical size standpoint system is relatively small
- System is dependable on interconnection with Russia for frequency regulation
- System dispatch in a large degree driven by heat supply requirements
- Power generation equipment is very old and do not allow for much flexibility in dispatch
- Only one generating plant is capable of load following
- Under these circumstances market with a clearing price formed on incremental cost based on free price offers seems unfeasible
- Current single buyer market model outlived its usefulness and no longer satisfies most of sector participants
- Transition to bi-lateral contract market model seems to be a right decision

19

Observations on current situation in Mongolia - continued

- The following options are possible:
  - Physical bi-lateral contracts for distribution companies estimated demand requirements
  - Financial bi-lateral contracts for distribution companies full or partial demand requirements
  - Combination of above
  - Bi-lateral contracts for payments
- All deviations are to be settled through a spot market

20

Observations on current situation in Mongolia - continued

- Things to be done in preparation to market implementation
- Acquire modern technical capability to conduct a dispatch and collect data required for settlement
- Prepare a data base on historic load profiles
- Complete transition to a 2-part tariffs
- Form an organization of market participants and stakeholder
- Develop and approve set of market rules
- Form at NDC a dedicated group of personnel and provide complete training
- Run a “mock market” exercise

21

The Main Lesson

Lesson 15 – Do not repeat some one else’s mistakes, you’ll have plenty of chances to make your own!

Questions ?

22

SECTION II: EVALUATION OF THE FUNCTIONING OF CURRENT "SINGLE BUYER" WHOLESALE ELECTRICITY MARKET IN MONGOLIA

1. Background

1.1 General overview of Mongolian electric power system

The electric power system in Mongolia consists of three independent electric power systems: the Central Energy System (CES), the Western Energy System (WES), and the Eastern Energy System (EES). In 2001 the Government of Mongolia (GoM) has taken major steps toward restructuring the energy sector by passing the 2001 Energy Law, establishing the Energy Regulatory Authority (ERA) and establishing a set of rules and regulations to promote private sector investments in the energy sector. The GoM has created 18 Joint Stock Companies (JSC) including generation, transmission and distribution entities and National Dispatch Center or NDC, which together comprise the energy sector.

The share entitlements of these companies (except NDC) were distributed as follows:

41% - to the Ministry of Infrastructure

39% - to the State Property Committee

20% - to the Ministry of Finance and Economy.

The NDC is responsible for dispatch of the CES transmission network. It was created as a LLC and its shares were distributed to the Ministry of Infrastructure (51%) and to the State Property Committee (49%).

The main Mongolian electric system is operated by the Central Energy System (CES) which represents 80% of all Mongolia electricity supply. The CES power supply is comprised of five coal burning generating plants and interconnection to UES of Russia. The other two networks – EES and WES are quite small. WES operates on imports of electricity from Russia, EES has one CHP with installed nameplate capacity of 36 MW, of which only 7 MW is available.

For the purposes of evaluation of market model in Mongolia the focus is on the CES system and its entities. Total installed nameplate capacity of CES is 753 MW of which only 633 MW are available. There is also a contract with Inter RAO of Russia to supply up to 160 MW of capacity through a double circuit 220kV line, normally operating at 110kV level. The contract is in effect through December 31, 2007. There is also a contract with Inter RAO for the export of power. The export is utilized to transfer excess power caused by heat demand during the off-peak electricity demand hours. Since the contractual price for exported power is very low, the export is in effect used to dump power.

1.2. Adequacy of generating resources to maintain reliability and quality of power supply

The existing capacity of CHP plants is generally sufficient from the point of view of installed capacity requirements of the power system with the annual peak of the order of 550 MW, which occurred this season in December 2005. However the power plants' equipment is in most part very aged, the youngest plant – Ulaanbaatar CHP 4 commenced its operation in 1981 and is the only plant capable of participating in frequency regulation, perform load following and to provide limited operating reserve. There currently is no capability to regulate system frequency and to withstand contingencies without reliance on the interconnection with Russia.

1.3. Transmission System and NDC

The CES transmission system interconnects three main load centers - Ulaanbaatar, Darkhan and Erdenet and the power plants in these cities by a 220kV transmission line ring. Transmission voltages are 220kV and 110kV, distribution voltages are 35kV, 10kV and 6kV.

The National Dispatch Center is responsible to coordinate daily system operation of all power and heat sector entities which includes the real time coordination of the power plants operation, transmission and distribution switching operations, operation of the heat transmission network in coordination with the CHP operations. The currently available hardware and software systems at NDC were not originally designed for the control of the power system network. All communications and data acquisition are mostly communicated by telephone and fax.

The NDC is also responsible for providing the information necessary to settle spot market transactions within the context of the wholesale electric power market which is currently structured on a "single buyer market" model. These responsibilities will be discussed in more details in the parts below.

2. The "Single Buyer Market" model – description and assessment of its efficiency

2.1 Transition to the "Single Buyer Market"

Immediately upon structural and functional reorganization of the national electric power system, the wholesale market transactions were implemented based on the system of vested bilateral obligations between distribution companies and generators. That system proved to be short-lived. Distribution companies were plagued with retail revenue collection problems. That and possible misappropriation of funds by distribution companies caused the situation where generating companies consistently under-collected a significant portion of the revenue needed not only to maintain the equipment but to pay their fuel suppliers.

Some generating companies also complained that the assignments of these bi-lateral obligations were unfair in the way that some generating companies were assigned most of the contracts with distribution companies with relatively high collection rates while other generating companies receive contracts with distribution companies with low collection rates. Although, as we were told, these bi-lateral obligations were legally enforceable in practice it was nearly impossible to obtain relief through the legal system. On average generators used to collect approximately 60 to 70% of the payments due them.

2.2. Description of the "Single Buyer Market"

Facing the above described problems in 2001, the ERA adopted a market model which became known in Mongolia as the "Single Buyer Market". Under this model there are no longer any bi-lateral obligations between generating and distribution companies. The flow of funds under this model is implemented through a Cash Management System (CMS) under which retail customers of state owned distribution companies deposit their payments into the so-called "zero balance" accounts established by each distribution company. These accounts prohibit any withdrawals by distribution companies. At the end of each day funds from these accounts are transferred into what is called "Main Zero Balance" account (MZBA), established in the Mongolian Savings Bank. Private distribution companies are not mandated to establish "zero balance" accounts and are allowed to make direct payments to the "Single Buyer". Disbursements to the market participants (distribution and generation companies) and to the dispatching entity are made from MZBA in

accordance with the pre-agreed allocation formula approved by licensees at their annual meetings, by the Transmission Company, which acts as if it were a Single Buyer. The CMS ensures that each entity receives a "fair" share of collections. However, the only entity that receives full payment due is a supplier of imported power. The amount of payments to other entities varies depending on retail revenue collection.

It has to be mentioned that because the funds allocation formula is based upon forecasted levels of consumption and generation, within the framework of the "Single Buyer" market, it is also necessary to operate a spot market, where generation companies settle deviations from planned output. Only generating companies participate in this market under the rules approved by ERA. The settlement between concerned generation companies is performed by adjusting the allocation of revenue due to these companies.

According to representatives of the ERA, Ministry of Fuel and Energy and generation companies, since the CMS system was introduced the collection rate of funds available to the "Single Buyer" for disbursement has improved significantly. For example according to the management of Ulaanbaatar CHP 4, the station now receives 97% of the revenue that would be due it based on generated energy and the approved generation tariff.

2.3. Assessment of the efficiency of the "Single Buyer Market" model

It has to be noted that characterization of the current system as a "Single Buyer" market is somewhat of a misnomer. The transmission company is not taking a title to the energy produced by generation companies, and is not legally responsible to pay them for what was actually supplied. It just simply allocates what funds are available to it in the MZBA redundant. This system also cannot be characterized as a power exchange in the traditional meaning of this word, since the settlement by funds allocation formula doesn't track payments to the actual amount of energy produced and consumed. In fact this system represents an operation of a vertically integrated utility which is functionally unbundled into several business units and whose corporate management vested responsibility to distribute collected retail revenue among business units in accordance with the pre-approved formula into only one of these business units (in this case - transmission company).

As such, this system has all advantages and disadvantages associated with the reliance by consumers on the operation of a vertically integrated utility.

The advantages of the current system are:

- Relative simplicity
- Allows easy balancing of supply and demand and settlement at deviations through the simple spot market settlement process
- Prevents misappropriation of retail revenue
- Provides financial stability to power sector entities
- Contributes to maintaining reliable power system operation under difficult local conditions

The primary disadvantages of the current system:

- It does not foster competition
- It allows government intervention into the settlement procedure

- It doesn't promote market relationship between distribution and generation entities
- It doesn't provide non-privatized distribution companies with sufficient incentives to improve collection of retail revenue

As was noted above, within the framework of the system, a spot market for energy to settle the deviation between planned and actual generation also is in operation. Only generators "participate" in this spot market.

The spot market functions in the following way: The daily regime planning group of the NDC develops generation dispatch schedules for the next "operating" day. During the "operating" day dedicated staff within this group tracks all deviations from the dispatch schedule, prices the energy deviations in accordance with the spot market rule developed by ERA staff and approved by the ERA and submits this data to the transmission company to be used subsequently for adjustments to funds distributed among generators as part of the funds allocation process. The spot market rule is somewhat simplistic and vague and doesn't take into account all possible situations. According to the rule, energy deviations should be priced at the respective energy tariffs or by combined tariff if the two-part tariff is not yet in place. That doesn't seem to be reasonable. As was noted above only generation deviation is settled through the spot market. Deviations on demand side are simply ignored. It is obvious that current spot market arrangements leave room for improvement.

3. Conclusion and recommendation

From the numerous discussions with power sector entities representatives it became obvious that implementation of the "Single Buyer Market" model played a positive role in the development of the national power system during difficult times.

It prevented the power system infrastructure from financial collapse and helped to maintain reliable operation of the power system by introducing financial stability to the power sector. However further movement toward privatization and introduction of competition into the power sector would require an introduction of market tools into the sector operation, such as bilateral contracts between distribution and generating companies, competitive bids in the spot market, participation of load serving entities in the spot market, etc. These developments can't be supported within the framework of the current system. If distribution companies are to be privatized the "zero balance" accounts will have to be abandoned or at least to a large degree, modified. Investors in new generation like to have an opportunity to enter into bi-lateral contracts with buyers and receive direct payments specified in contractual terms. It is obvious that the current system is in need of changes. In our opinion the current system should be transformed to a system based on bi-lateral contracts between generation and distribution companies, supplemented by an orderly spot market, where both generation and distribution entities settle their deviation. In the beginning, bi-lateral contracts and the spot market could be based on regulated tariffs (two-part tariffs will have to be developed) and within several years gradually transition to a mostly competitive market.

Preparatory work needs to be done before the new system is implemented, i.e., examination of existing legal arrangements, introduction of two-part tariffs for generation, development of market rules and procedures, development of a standard contract for sale/purchase of electricity, training of NDC staff, upgrading NDC technical capabilities to control real time power system operation and to perform settlement and billing functions. A system of third-party financial guaranties

would have to be developed. Alternatively some elements of the current cash management system may be employed as part of contractual arrangements.

There is no urgent need to rush a transition until all above listed milestones are accomplished. Only after market participants can demonstrate accountability, honor their contractual obligations and pursue disputes in accordance to existing regulations and laws should the new market model be implemented.

SECTION III: EVALUATION OF THE NDC's TECHNICAL CAPACITY TO PERFORM THE FUNTION OF THE INDEPENDENT MARKET OPERATOR

1. Introduction

This evaluation is performed as a part of an assignment to develop a set of implementable market rules and operating procedures to assure a transition of power market structure of Mongolia from the current "Single Buyer Market" model to a market model based on bi-lateral contracts supplemented by a spot market. The evaluation is limited to the assessment of the National Dispatch Center (NDC) staff's capability to perform the function of the market operator, such as development of dispatch schedules, implementation of bi-lateral agreements between generation and load serving entities, monitoring of actual market participant's performance, administering the spot market, performing market settlement and billing, collection and disbursement duties.

Assessment of the NDC's capability to perform the function of a system/market operator such as metering, telemetering, data acquisition and communication with interconnected entities using modern hardware and software is a part of a separate task order and is not discussed here.

2. General description of NDC responsibilities

As in any electric power system, the National Dispatch Center (NDC) plays a key role in operating the power system.

The NDC is responsible for dispatch of the Central Energy System transmission network (CES) in a reliable and safe manner. CES is the main Mongolian electric system which represents 80% of all Mongolia power supply. The NDC was created as a LLC and its shares were distributed to the Ministry of Infrastructure (51%) and to the State Property Committee (49%).

The CES power supply under NDC dispatch is comprised of five coal burning generating plants and interconnection to UES of Russia.

The main responsibility of the NDC is to assure the safe, reliable and efficient operation of the interconnected electric power system. This is accomplished by issuing operational instructions to the generating stations, substations, transmission and distribution companies; preparation of load forecasts; calculation of electrical and thermal regimes; development of dispatch schedules; coordination of the outage schedules for generating and transmission equipment; and coordination of power restoration after power outages. In addition to this the NDC is responsible for providing the data necessary to settle the spot market for electric energy which operates under the current "Single Buyer" market framework. These responsibilities involve tracking all generation stations' deviations from the dispatch schedule, pricing these deviations in accordance with ERA approved spot market rules and submission of this data to the transmission company which is responsible for the market settlement and billing.

3. NDC's responsibilities as a Market Operator

The envisioned new market structure presumes that the NDC becomes the market operator with a much wider set of responsibilities. It is envisioned that in addition to its traditional responsibilities as a technological power system operator, the NDC will assume a full set of responsibilities associated with administering the electric power market. These responsibilities include:

- Collecting a variety of information associated with their market activities, such us details of bi-lateral contracts, energy bids (when allowed), proposed outage schedules, etc. from market participants.
- Maintaining confidentiality with regard to market related information
- Collecting from the NDC's operational staff information regarding forced outages and unsanctioned generation deviation and to record this information
- Preparation of dispatch schedules
- Monitoring and recording market participants performance data
- Maintaining the data base of market related data
- Performing market settlement, billing, collection and disbursement functions related to licensees
- Providing explanations to market participants and concerned authorities with regard to decisions undertaken in the course of the system operation and market administration
- Performing all responsibilities listed above in a strict compliance with approved market rules
- Provide training to market participants with regard to market rules and procedures

Only a limited part of these responsibilities are performed by the NDC's staff now.

4. Assessment of NDC's ability to act as a Market Operator

4.1. General Organization of the NDC

The organizational structure of the NDC is shown in Attachment below:

The NDC's core business departments are Dispatching/Technological Management department and Regimes Department. Their operation is supported by the Communication and Information department. Currently there is a special Project Implementation Group formed directly under the General Dispatcher to support implementation of the SCADA system.

The NDC's Executive Director is responsible for the day-to-day operation of the organization. Department of the administrative, legal and marketing support is reporting directly to the Executive Directors. All other departments report to the Vice Director/General Dispatcher who in turn reports to the Executive Director. The total number of the NDC staff is 42 person.

Currently market supporting activities are concentrated in the Dispatching and Regimes Department. The Regimes Department consists of two teams – relay protection and automatics and Regime Planning team. The Regime Planning team is responsible for calculation of electrical energy and thermal regimes and for the development of the dispatch schedule. Also this group is responsible for tracking generating plant performance, deviations from the dispatch schedule, pricing of the generation deviations in accordance with the spot market rules and submittal of the information to the transmission company for settlement purposes. The team consists of 7 persons; one of them is dedicated to the tasks of tracing deviations and preparation of spot market data to be submitted to the transmission company. Calculations of the electrical regimes are performed using the special software – load flow programs. Other calculations are either performed manually or by using spreadsheet based programs, with manual data entry.

The Dispatching/Technological Control Department consists of 12 persons, mostly dispatchers. Communications with the licensees regarding dispatch control are conducted by telephone and fax. A significant part of the power system is not continually monitored from the control room.

Dispatch instructions and related information are recorded in a special logbook, entry to which is performed manually.

4.2. Assessment of the NDC ability to function as a system/market operator

To continue operate the power system under the current market arrangements, the NDC needs to enhance its data acquisition and communication capabilities as well as acquire modern software for regime calculation, data maintenance and economic calculations. To implement new market arrangements, the NDC responsibilities regarding system/market operations the current NDC's capacity is inadequate.

With regard to dispatcher capabilities to monitor the state of the power system, the situation will improve significantly with the implementation of the "SCADA" system in the new modern control room. These projects are being performed in cooperation with a team of experts from Siemens and are expected to be completed in April of 2006.

Whether these would be sufficient for the new market structure will be determined as part of the assessment of the NDC's capability to perform the functions of a system/market operator such as metering, telemetering, data acquisition and communication with interconnected entities using modern hardware and software. This assessment will be performed as part of a separate task order.

With regard to the responsibilities associated with market administration, settlement, billing, etc., the current NDC's capacity is wholly inadequate.
A separate functional unit needs to be formed which would be dedicated to perform the market administration duties. This unit needs to have an adequate, trained staff, be equipped with modern computerized tools to perform such tasks as load forecasting, load flow and production cost simulation analyses, development of dispatch schedules, generating settlement statements and invoices, etc.

5. Conclusion and recommendation

As follows from the assessment contained in Part 4 the current NDC's capacity to fulfill responsibilities associated with the functions of the System/Market operator is inadequate, as noted in Part 4. Significant enhancements in the areas of workforce and technical tools will be required to bring the NDC to the level of being able to function as a modern power system/market operator.

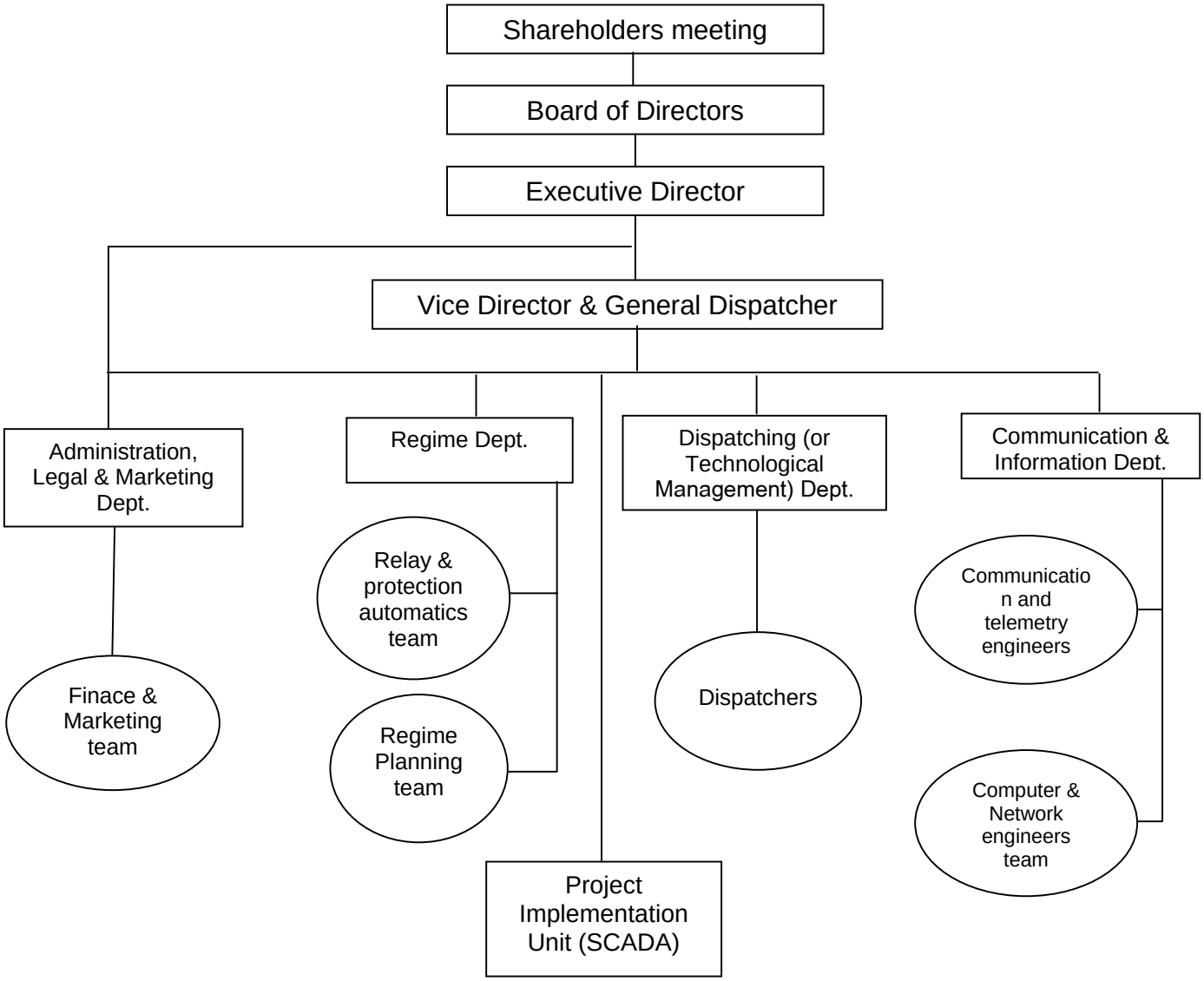
We recommend that the following measures be implemented in order to bring the capacity of the NDC to function at a level adequate to satisfy the responsibilities of the system/market operator:

- Complete implementation of the "SCADA" system and construction of a new control room
- Implement recommendations resulting from the technical assessment of the NDC's capability to perform the functions of a system/market operator as metering, telemetering, data acquisition and communication with interconnected entities using modern hardware and software
- Form a special adequately staffed department dedicated to fulfill market administration responsibilities within the NDC
- Support the staff dedicated to the market administration with modern computerized tools to perform such tasks as load forecasting, load flow and production cost simulation

analyses, development of dispatch schedules, generating settlement statements, invoices, etc...

- Develop the necessary software to perform market administration functions. The software should be strictly consistent with the market rules and procedures
- Provide comprehensive training for the entire NDC staff on their responsibilities under the new market structure
- Implement all necessary "code of conduct" rules

Attachment


Shareholders meeting
Board of Directors
Executive Director
Vice Director & General Dispatcher
Administration, Legal & Marketing Dept.
Regime Dept.
Dispatching (or Technological Management) Dept.
Communication & Information Dept.
Finace & Marketing team
Relay & protection automatics team
Regime Planning team
Dispatchers
Communicatio n and telemetry engineers
Computer & Network engineers team
Project Implementation Unit (SCADA)

SECTION IV: CONCEPTUAL DESIGN OF MONGOLIAN WHOLESALE POWER MARKET

USAID FROM THE AMERICAN PEOPLE

Economic Policy Reform and Competitiveness Project

Conceptual Design of Mongolian Wholesale Power Market

USAID FROM THE AMERICAN PEOPLE

Economic Policy Reform and Competitiveness Project

Basic Concepts

- Market Participants
  - Infrastructural
  - Commercial
- Stakeholders Organization
- Market Design
  - Bilateral Contracts
  - Spot (balancing) Market
  - Market Rules
  - Transmission Losses
- Financial Guarantees
- Market Governance

Market Participants

Infrastructural:

- Transmission Company:
  - Provides Transmission Services for all commercial market participants
- The System Operator – created on basis of NDC
  - Ensures technological functioning of the power system
  - Performs the role of market administrator:
    - Operates spot market
    - Performs settlement and billing functions, clears the spot market

3

Market Participants - continued

Commercial Market Participants

- Generating Companies
- Distribution Companies
- Wholesale Marketers
  - Import/Export Licensees
- Eligible Consumers (if any)

4

Stakeholders Organization

- Stakeholders are parties who have a stake in successful market operation
- Consumers of electricity
- Government Agencies
  - Ministry of Fuel & Energy
  - Legal Authorities
- Consumer Advocates
- Market Participants
- Stakeholders form an organization which has advisory role where market participants may vote on market related issues
- At least 2 committees are formed in the beginning
  - Reliability and planning
  - Market operation and business issues

5

Market Design – bilateral contracts

- Market design is based upon the system of bilateral contract supplemented by a spot market
- Bilateral contracts:
  - 1st year – vested contracts cover entire anticipated demand of distribution companies and eligible consumers, if any
  - All capacity of generating companies are allocated by ERA under bilateral contracts to distribution companies based on generating companies' 2-part tariff – energy and capacity
  - Combination of generating companies for each distribution company should assure that resulting wholesale purchase cost is close to what it currently is
  - Distribution Companies are responsible for direct payments to generating companies in accordance with contract terms
  - Contracts may specify for each generation capacity entitlement either associated with this entitlement energy or fixed amount of energy
  - After each year of operation ERA in consultation with stakeholders' organization may reduce the percentage of demand covered by vested contracts
  - Contracts are financial but generating units with the consent of System Operator may choose to physically execute contracts
  - Contracts should contain provisions regarding generation units availability

6

Market Design – Spot Market

- All deviations from bilateral contracts are settled in the spot market
- Spot market is operated by the System Operator
- All commercial market participants participate in the spot market and could act as sellers and buyers
- All transactions in the spot market are based on energy component of the 2 part generation tariff and import contractual energy price
- Spot market settlement interval is 1 hour, all hourly settlement data are accumulated in a monthly billing statements

7

Market Design – Spot Market - continued

Payments to/from in the spot market are calculated as:

P = (Eact – Ebc)*T, where:

P - payment due to/from, $

Eact – energy actually produced/consumed in a given hour, MWHR

Ebc - energy obligation/entitlement under bilateral contract, MWHR

T – an energy component of the generator's tariff or import contract price specified in the Market Rule, $/MWHR

8

Market Design – Market Rules

- Market rules are needed to assure orderly operation of the power market
- Market rules should reflect and be consistent with chosen market structure/market design
- Compliance with market rules is mandatory for all market participants
- In the process of real time market operation the System Operator has the final authority in interpreting market rules
- No market rules are forever but all market rules changes should be made in accordance with market governance provision and be approved by ERA
- The 1st draft of market rules is currently under translation and will be available for stakeholders review some time next week

9

Market Design – Transmission Losses

- Tariff for transmission service should reflect transmission losses
- Generating companies is paid for the full volume of energy produced, including transmission losses
- Transmission losses is the difference between the energy delivered by generators to the transmission system and the energy delivered by transmission system to distribution companies points of receipts
- The ERA should set the level of technically justifiable transmission losses. If losses exceed the technically justifiable level transmission company becomes responsible and will compensate distribution companies for the energy lost due to the excessive losses

10

Financial Guaranties

- Responsibility and accountability with regard to fulfillment of financial obligations under bilateral contracts and spot market is an absolute requisite for successful market operation
- Bilateral contracts should contain provisions that protect parties against failure by contractual parties to fulfill their financial obligations under the contracts
- Bilateral contracts are enforceable in the court of law
- To protect market participants against failure of some participants to live up to their financial obligations the system of financial assurances should be established
- ERA in consultation with stakeholders committee on market operation and business issues should develop the level of financial assurance that commercial market participants should maintain to guarantee their financial obligations in the spot market
- If the System Operator draws against participants' financial assurance the respective participant is obligated within specified time to restore the required level of assurance

11

Market Governance

- The key entity in the governance of the market is the System Operator – in the process of administering market operation in accordance with market rules monitors the market operation, initiates rule changing, reports "bad" behavior, publishes reports, etc..
- Stakeholders committees initiate and review proposed market rule changes
- ERA is a market regulator - approves market rules, initiates and approves market rule changes, responsible for overall monitoring of market activities

12

SECTION V: RULES FOR THE WHOLESALE POWER MARKET OF MONGOLIA NATIONAL POWER SYSTEM

1. Introduction and market rules

1.1. Introduction

These market rules establish the order for the functioning of the wholesale power market for the Central Interconnection of Mongolia National Electric Power System (subsequently the wholesale power market or WPM), which is based upon bilateral contracts for the wholesale sales/purchases of electric energy (capacity) between market participants and include provisions, associated with:

1. annual activities of the wholesale power market;
2. activities to introduce monthly adjustments into bilateral contracts;
3. procurement of ancillary services;
4. requirements and obligations regarding presentation of information on market activities; and
5. central economic dispatch of power system generation based upon minimizing of variable operating expenses over the dispatch period as described further in this document while taking into account central heating requirements and power system constrains.

1.2. Goal of these wholesale power market rules

The Goal of these market rules is to create a normative ground and legally binding set of procedures based on Mongolian Energy Law that will facilitate development of an efficient market for the wholesale sales and purchases of electric energy (capacity), while ensuring safe and reliable operation of the electric power system in accordance with accepted criteria and reliability rules.

1.3. Definition

1. **Technical evaluation -** Process of evaluation by the System Operator of individual contract or a group of bilateral contracts for purchase/sale of electricity with the goals to establish whether the terms of the contracts are consistent with power system reliability requirements and identification of which contracts or group of contracts can not be physically executed.
2. **Commercial Market Participants -** Market participants which have commercial interests in market operation results (generation and distribution companies, traders)
3. **Infrastructural Market Participants -** Market participants who support the infrastructure for market operation but themselves do not have a commercial interest in market operation results (System Operator, Transmission Company)
4. **Spot market -** The marketplace where commercial market participants settle deviations between actual and contractual quantities of energy generated and/or consumed in accordance with a set of established rules
5. **Stakeholders' organization -** Organization of market participants and other parties that have an interest in successful operation of the power market which reviews all issues associated with market operation and in accordance with established procedure provides an advisory input to the System Operator and/or ERA on market operation issues

6. **Technological ancillary services -** Systemwide technological services arranged by the System Operation on behalf of market participants to assure safe and reliable operation of power system, that benefit not an individual market participant but an entire community of power system users (frequency and voltage regulation, operating reserves, black start, etc...)
7. **Reserve capacity -** Difference between the sum of generating capacity and dispatchable/interruptible load, if any, and the customer demand
8. **Rated capacity -** Capacity of a generating unit which was confirmed by capacity testing in accordance with special procedures established by the System Operator. Rated capacity of a generating plant is determined as a sum of the rating capacities of all generating units at the plant.
9. **Unforced rated capacity -** Rated capacity adjusted to reflect generating unit availability, calculated as described in Attachment 2.
10. **Available capacity -** Generating capacity that at given period of time is either generating electric energy or at a reasonable time notice is capable to be synchronized and generate electric energy
11. **Availability factor -** A number between 0 and 1 which characterizes a degree of readiness of a given generation unit/plant to produce energy and is calculated in accordance with a procedure described in Attachment 2.
12. **Financial assurance -** System of financial guaranties provided by commercial market participants to provide the System Operator with assurance that it will be able to perform the market settlement with regards to market participants to whom payments are due, notwithstanding of a default of individual market participants on their payment obligations for a reasonable period of time until default is cured or defaulted market participant is terminated

1.4. Application of the wholesale power market rules provisions

1. These wholesale power market rules are applied to:
   a. Producers and suppliers of electric energy (capacity);
   b. Distribution Companies;
   c. Operators of import and export of electric power;
   d. Transmission Company
   e. National Dispatch Center of Mongolia Electric Power System, subsequently the System Operator
2. These wholesale power market rules also establish certain obligations upon the System Operator and Licensees with regard to dispatch control, technical evaluation of bilateral contracts, as well as with regard to regimes planning and forecasting of parameters of system reliability.
3. Energy Regulatory Authority (subsequently "Authority" or ERA) in accordance with authority granted to it approves initial wholesale power market rules and subsequently monitors market operation and possible ways of it development and is responsible for initiating necessary changes to the market rules and for organizing procedure for the

regular hearings to review proposals regarding changing of the wholesale power market rules which can be presented by ERA, commercial market participants and by System Operator and Transmission Company. The established procedure should provide an opportunity for all market participants to provide a meaningful input into decision making process.

4. The System Operator in the process of fulfilling its functions with regard to dispatch control should require that all market participants comply with certain requirements, associated with maintaining power system security and stability in order to assure reliable power supply to consumers. These requirements should be based upon criteria and reliability rules as adopted for the National Power System of Mongolia, otherwise the System Operator's influence on commercial relations among market participants should be confined to the power system regime's planning and real time operation and to the procedure of conducting technical evaluation of bilateral contracts. Based upon the results of the technical evaluation the System Operator can terminate or limit the execution of certain contracts and/or to require or recommend changes into amount of capacity specified under bilateral contracts.
5. In accordance with these market rules all market participants have the right to access **all** non-confidential and non-proprietary information related to the bilateral purchase/sale contracts and agreements with regard to services provided by the Transmission Company and the System Operator..

1.5. Main principles of the wholesale power market

These wholesale power market rules are served as a normative basis to facilitate purchases and sales of electric energy and capacity on the wholesale power market where:

1. The commercial relations between buyers and sellers rest upon annual bilateral contracts for purchase/sale of electric energy and capacity that envision monthly settlement and direct payments from buyers to sellers. These annual bilateral contracts should allow monthly adjustments of contractual volumes of energy and capacity and are supplemented by the spot market where deviations of actually produced/consumed energy from contracted volumes are settled.
2. All electric power resources (electric energy and capacity) that are included in the bilateral contracts of distribution companies are subject to the central economic dispatch by the System Operator based on generation units variable costs as determined by generating unit thermal efficiency, fuel and variable operating and maintenance costs, while taking into account central heating requirements, transmission losses and power system constrains with the goal to achieve minimization of power system's variable operating costs for the dispatch day and to assure maximum possible economic efficiency for distribution companies.
3. Producers and suppliers sell electric energy and capacity pursuant to tariffs established by ERA which include supplying ancillary services.
4. Distribution companies purchase electric energy and capacity from producers in accordance with bilateral contracts. The pro-forma purchase/sale contract should be approved by ERA. The electric energy delivery point should be the border of producer and

Transmission Company. Transmission of the energy from producer's delivery point to the border of the distribution company is provided under the transmission services tariff.

5. In accordance with these rules the System Operator has a right to demand that market participants provide technological ancillary services. These ancillary services are provided by market participants pursuant to their license obligations and it is assumed that cost of providing ancillary services is reflected in market participants respective tariffs.
6. In special cases under agreement with the System Operator generators may be allowed to self-schedule and to work at the requested load level, providing that the payment for the energy produced under such operation does not exceed the cost of displaced energy. The System Operator and its Settlement department shall develop and submit for ERA approval the rules for such operation.
7. Importers and Exporters of the electric energy and capacity purchase and sell power at the negotiated prices. The delivery/acceptance point for imports and exports are set at the state border of Mongolia and transmission of the energy from the border to the distribution company or from the producer to the border is provided in accordance with transmission service tariff.
8. The System Operator within the framework of technical evaluation of bilateral contracts shall ensure that bilateral contracts include sufficient volume of capacity, including reserve capacity to secure the adequate level of power system reliability and in this regard shall introduce necessary adjustments to bilateral contracts.

2. The system of the wholesale bilateral contracts

2.1. Purchase and sale electric energy and capacity

1. The wholesale power market is based upon the system of bilateral contracts for the purchase/sale of electric energy and capacity, which shall include:
   a. Bilateral contracts between distribution and generation companies;
   b. Bilateral contracts between generating companies and exporters;
   c. Bilateral contracts between importers and distribution companies;
2. The bilateral contracts for purchase/sale of electric energy and capacity between the transmission company, which serves as an importer/exporter and Inter RAO UES of Russia shall become an integral part of the wholesale power market structure.
3. All deviations of actual generation and/or consumption from the contracted energy volumes will be settled at the spot (balancing) market in accordance with provisions of Part 5.3.

2.2. Payments for the services of the Transmission Company and the System Operator

1. Transmission Company Services:
   a. Paid by distribution companies in accordance with the tariff approved by ERA;
   b. Individual bilateral point-to-point wheeling contracts with importers and exporters under special tariff approved by ERA
2. The System Operator Services:

a. Paid by distribution companies in accordance with the tariff for System Operator services approved by ERA;
b. The System Operator tariff covers services associated with power system which are provided to all power system users, except importers and exporters, and services associated with market settlement and billing activities;
c. Services related to import and export transactions, except under the existing contract with Inter RAO UES of Russia are paid under individual tariffs approved by ERA.

3. Payment obligations of distribution companies to the System Operator and Transmission Company are determined by the System Operator and invoices for the Transmission Company and the System Operator services are issued monthly by the System Operator to distribution companies. Payments in accordance with invoices for both services are made to the System Operator. System Operator then transfers the funds due for transmission services to the Transmission Company.

3. Wholesale Power Market's management structure

3.1. Wholesale electric power market normative base

The wholesale power market of Mongolia Power System is based upon following documents:

1. Energy Law of Mongolia;
2. Licenses issued by ERA;
3. These market rules, approved by ERA in accordance with Energy Law which are complemented by market and power system operating procedures and by following documents issued by relevant authorities:
   a. Grid Code of operating Mongolian National Power System (Grid Code);
   b. Business rules among the licensees;
   c. Power system interconnection rules as detailed in a respective sections of Grid Code;
   d. Provisions for providing financial assurances (yet to be developed and approved by ERA);
4. Bilateral and multilateral agreements listed in Part 2.

3.2. Wholesale electric power market administration, management and regulation

1. The responsibilities regarding wholesale power market administration, including implementation of bilateral contracts for purchases/sales of electricity is vested upon the System Operator who acts in accordance with these rules, rules for power system technological operation that ensure safe and reliable operation of power system, and with other normative documents.
2. In order to provide for all market participants an open access to the decision making process with regard to the wholesale power market and power system operation and to facilitate future wholesale power market development by means of introduction changes and amendments into wholesale power market rules market participants shall form an organization of market stakeholders with the goal to:

a. Establish a procedure for market participants interactions with the Transmission Company and the System Operator regarding the fulfillment by these entities of their functions and obligations;
b. Publish semi-annually data regarding wholesale power market operation (including data regarding accuracy of load forecasting, average prices resulted from economic dispatch, capacity availability factors, forced outage rates, volumes of export and imports, number of outages, time for system restoration, etc...)
c. To organize the following permanently functioning committees with the responsibilities to facilitate resolution of the market related disputes, joint resource planning, development of recommendations regarding wholesale power market rule changes and amendments to be submitted for ERA approval:
   i) Committee for reliability, power system planning and operation;
   ii) Committee for market operation and business issues.

3. In the period before the stakeholder organization in accordance with provision of the Part 3.2.2 is established the ERA may issue an order to establish the committees listed under the Part 3.2.2(c). The ERA order should establish committees authority and an order for decision making process.
4. ERA is responsible for the regulation of the wholesale power market operation within the authority granted to it by the Law of Electricity and the Law of regulation of public services, including but not limited by issuing of licenses to market participants, approval of the market rules, approval of pro-forma contracts to be used on the wholesale market and approval of changes and amendments to the market rules.

4. The duties of the System Operator

4.1. System Operator's duties with regards to market administration

1. The System Operator must dispatch the power supplies that are included in the wholesale power market's bilateral contracts and to facilitate technical support to market participants in the process of commercial power exchange in accordance with these rules, as well as to provide all other services pursuant to the requirements specified in its License, as well as services such as:
   a. Management of the central economic dispatch process, including publishing of preliminary dispatch schedules;
   b. Technical evaluation of bilateral purchase/sale contracts;
   c. Organization and coordination of the short and middle range power system regimes planning;
   d. Preparation and publishing of statistical information regarding market operation;
   e. Collection and publishing of information necessary for efficient operation of the wholesale power market;
   f. Collection of the information from the distribution companies regarding retail demand for electric energy and capacity;
   g. Support activity of Stakeholder Organization.

2. The System Operator should possess all necessary means to facilitate all wholesale commercial activities of market participants. At the same time the System Operator should not have financial interests in the results of business activities of commercial market participants;
3. In order to ensure safe and reliable operation of the power system the System Operator based on the results of the forecast of the reliability indicators of the power system and/or upon the results of the technical evaluation of bilateral purchase/sales contracts may require changes in the volumes of electric capacity, acquired pursuant to bilateral contracts;
4. Under certain conditions specified in Part 12 of these rules the System Operator may suspend the wholesale power market activities.

4.2. Responsibilities of the System Operator with regards to maintaining the reliability of the power system

1. In accordance with these rules the System Operator shall conduct real time operation of the power system in a manner to maintain power system reliability requirements.
2. The System Operator shall plan power system regimes in accordance with Part 8 of these rules and to publish detailed description of results of regime's calculations and forecast of power system reliability indicators and as required to undertake the actions in accordance with these rules to maintain the power system security and reliability.

4.3. Technological Ancillary Services

1. Providing of technological ancillary services is currently a part of producer's responsibilities pursuant to their license requirements. The technological ancillary services therefore is paid within the framework of producer's tariffs.
2. The System Operator has a right to demand that ancillary services be provided by market participants as required.
3. The System Operator has a right to establish the list and ranges of ancillary services to be provided by market participants.

4.4. Reserves

These market rules do not envision a separate operating reserve market. The System Operator as part of its responsibilities shall ensure that provisions of bilateral contracts ensure an adequate volume's of reserve capacity.

4.5. Import and Export Agreements

System Operator may introduce suggestions with regard of procurement of power from and selling power to interconnected national power systems.

4.6. Financial Responsibility of the System Operator

These rules do not establish financial responsibility for System Operator for any financial loss or damages suffered by market participants as a result of action or inaction of the System Operator in

addition to the responsibility, defined by the laws in effect at this time and by bi and multilateral agreements to which the System Operator is a party.

5. Market arrangements for purchase/sale of electric energy and capacity

5.1. Bilateral agreements on the wholesale power market

1. Bilateral agreements for purchase/sale of electric energy and capacity on the wholesale power market are entered into by market participants initially for the term of one year with an opportunity to introduce monthly adjustments to modify volumes of energy and capacity. The pro-forma purchase/sale contract must be approved by ERA.
2. The bilateral contracts should specify volume of energy and capacity and the terms of the purchase/sale. The amount of capacity to be provided by producers is indicated for each month and should reflect reserves necessary for the safe and reliable operation of power system. Payments for capacity should be made monthly and to reflect its actual availability. The volume of energy specified in the contracts is indicative and is provided for the purposes of fuel procurement planning by the producers.
3. The capacity, offered on the wholesale market should first and foremost be used to satisfy the needs of distribution companies and eligible consumers, if any, within Mongolia. There should be no firm energy sold for export unless the peak requirements of Mongolia customers are fully covered.
4. In the first year of wholesale power market operation all available generating companies' capacity should be included in the vested wholesale power contracts with distribution companies. The initial allocation of the capacity and energy of generation companies to be included in these vested bilateral contracts with each distribution company and eligible customers if applicable is done by the ERA based upon two-part producer's tariff (energy and capacity) and assuring as close level of resulting distribution companies costs to their current wholesale purchase costs as possible. The other factors such as distribution companies customers' payment patterns should also be taken into account to assure fair and non-discriminatory allocation of capacity. In the first year of market operation all distribution companies planned power needs should be covered by the vested bilateral contracts.
5. By the end of the 1st year of the wholesale power market operation ERA together with the System Operator with input from the stakeholders shall conduct an analysis of market operation and based upon it to consider recommending a reduced level of capacity needs of distribution companies and eligible consumers, if any, to be covered by vested bilateral contracts. To satisfy their remaining needs distribution companies shall be free to enter into freely negotiated market based bilateral contracts or to procure the balancing power from the spot market.
6. The actual energy entitlement of distribution companies in the energy output of generation companies is determined by the pro-rata share of the given distribution company in the capacity of given generation company or may be directly specified in bilateral contracts. The energy payments by distribution companies to generating companies under bilateral contracts should be calculated as the product of its energy entitlement specified in the contract or computed as a percentage of contractual capacity entitlement, expressed in MWHR and energy component of the two part tariff of the generation company.

7. Capacity payments under bilateral contracts are calculated each month as a product of amount of capacity specified in the contract and expressed in MW, the capacity component of the two part tariff of given generator, expressed in $/MW-month and a number between 0 and 1, reflecting the availability of given generating company as it relates to the average availability of all power system generation. The process of calculations of the availability factors is contained in Attachment 2. All input information of these calculations should be in possession of the System's Operator settlement department. Until the procedure for determining the availability factors is approved by ERA, the availability factors shall be deemed as equal to 1.
8. Within 6 months from the commencement of market operation ERA, upon submission by respective stakeholders committees or by the System Operator if market stakeholders committees are unable to reach a consensus, should approve special instructions and/or guidelines regarding periodic verification of available contractual capacity, procedure for conducting availability tests and calculation of availability factors.

5.2. Responsibility for satisfying load obligations

1. The distribution companies are responsible for the development of its energy consumption and peak load forecasts. Before October 1 of each year distribution companies shall submit to ERA and the System Operator its peak load and energy demand forecasts for development and technical evaluation of its vested contracts.
2. An indicative forecast of distribution companies total consumption and hourly loads is developed for the entire year. Distribution companies may adjust their annual forecast on a monthly basis by submitting monthly adjustments to the System Operator no later than 5 days before the beginning of each month.
3. Responsibility for the capacity reservation payment pursuant to import contract with Inter RAO UESR shall be allocated monthly to the distribution companies and eligible suppliers, if any, pro-rata to their monthly non-coincidental peak loads as follows:

   ICd = IC*MPd/∑MPd, where

   ICd - distribution company share of monthly capacity reservation payment, $

   IC - monthly capacity reservation payment obligation under contract, $

   MPd - distribution company hourly peak load in a given month, MW

   ∑MPd - sum of non-coincidental hourly peaks of all distribution companies in a given month, MW

5.3 Balancing (spot market) provisions of the wholesale power market

1. The day before the each operating day the System Operator shall develop the hourly load forecast and preliminary dispatch schedule for each hour of the operating day and communicate it to respective market participants. In developing the dispatch schedule and in the process of real time operation the System Operator should to the best of its abilities conform to bilateral contracts while pursuing the goal of maintaining power system reliability and security and minimizing the total system operating costs. The generating companies are responsible for prompt submittal to the system operator of all operational data regarding generating units availability.

2. For the each hour of each operating day the System Operator should maintain the information regarding the actual system operation with information of all deviation from the dispatch schedule duly recorded along with the reason for the deviations. The System Operator's settlement department should calculate for each hour payments due to/from market participants as following and to aggregate them into the monthly invoice at the end of each month:

   a. Payments by/to distribution companies are calculated as:

      Pd = (Ea – Ebc)*Tc, where

      Pd - payment obligation (receivable) in $,

      Ea - actual energy consumption, including transmission losses, MWHR,

      Ebc - energy available to distribution company under bilateral contract, MWHR,

      Tc - Energy component of the two-part tariff of the most expensive producer of energy on line in a given hour (including import) that is available to increase its generation, $/MWHR

      The negative value indicates that payment is due to the distribution company;

   b. Payments to/by generation companies are calculated as:

      Pg = (Ga – Gbc)*T, where

      Pd - payment obligation (receivable) in $,

      Ga - actual generation into the grid consistent with dispatch instructions, MWHR,

      Gbc - generation obligation to distribution companies under bilateral contracts, MWHR,

      T - Energy component of the two-part tariff of the most expensive energy producer on line in a given hour that is available to increase its generation, if Ga is less than Gbc, or energy component of the given generator's two-part tariff of the most expensive energy block on line in a given hour that is available to increase its generation, if Ga is more or equal than Gbc, $/MWHR

      The negative value indicates that payment is due from the generation company;

   c. If the generation company deviated from dispatch instructions by generating more energy than required in accordance with dispatch instructions the energy produced in excess of what would be produced if the dispatch instructions had been followed is paid at the energy component of the ERA approved two-part tariff of the least expensive energy producer currently on line whose energy was displaced as a result of non-compliance with dispatch instruction.

   d. No later than the 5th day of each month the System Operator's settlement department shall aggregate the hourly data into monthly billing statements and issue invoices to market participants. All payments due from participants for the previous month shall be received at the settlement department's special account receivable by the 10th day of the current month. Participants to whom payments are due shall receive payments due for the previous month from the settlement department by the 20th day of the month.

e. If market participant disagree with an invoice issued by the System Operator it may within 1 month from receiving an original invoice request a billing adjustment. The request shall be accompanied with all available supporting documentation. The System Operator shall review the request and to render its decision within 2 weeks. If request for a billing adjustment is satisfied the next month invoices shall contain necessary adjustments as a separate line item and payments due to/from shall reflect these adjustments. Participants that dispute their invoices by requesting billing adjustments are still responsible for a full and timely payments in accordance with original invoice. If request for billing adjustment is denied by the System Operator the market participant may appeal the System Operator decision to ERA.

4. ERA in consultation with market participants shall establish a system of financial assurances to ensure the availability of funds for the settlement of spot market obligations.
5. The System Operator should notify ERA and market stakeholders regarding any market participant's non-compliance with provisions of financial assurance which result in market participants not maintaining a sufficient amount of financial assurance and if situation is not remedied within one week since such notification is issued the balancing power supply to this market participant should be curtailed.
6. If any market participant doesn't pay its bill by the due date it is liable for the interest accrued from the due date to the actual payment date based at the interest rate 1.5% per month. If the payment is not received by the 20th day of the month the System Operator shall act in accordance with provisions of financial assurance policy.

5.4. Purchase of power by generation companies for station and own usage

The way of Purchasing of energy by generators for the station service / own usage when off line depends on the way of its interconnection to the transmission system:

1. if the generator is interconnected using distribution company equipment then the power is paid for at the ERA approved retail tariff of the distribution company for the respective consumer category;
2. if the generator is not using the distribution company equipment for interconnection to the transmission system then the power is paid for at the energy component of the ERA approved two-part tariff of the most expensive producer that is on line and is available to increase its generation.

6. Monthly adjustments to annual bilateral contracts

6.1. Distribution companies responsibility

Each distribution company is responsible for adjustment of its contractually specified volumes of energy and capacity if it foresees changes in customer demand. If it elects to do so it needs to notify the System Operator as well as its contractual counterparts of its intention no later than 20th day of the month preceding the month for which contractual adjustments are proposed. System Operator shall evaluate proposed changes within 5 days and no later than 5 days before the 1st day of the operating month to render its decision regarding requested changes and to notify contractual parties concerned.

6.2. Generation companies responsibility

Each generation company is responsible for notifying the System Operator and its contractual counterparts for any known changes to its available capacity no later than 7 days before the 1st day of the operating month. System Operator shall evaluate proposed changes within 5 days and no later than 5 days before the 1st day of the operating month to render its decision regarding requested changes and to notify contractual parties concerned.

6.3. The System Operator responsibility

1. The System Operator forecasts independently of distribution companies the total level of power system energy and capacity demand for each month
2. Based on its forecast of power system conditions and proposed monthly adjustments by distribution and generation companies the System Operation shall if it deems necessary to approve proposed or to initiate monthly adjustments to bilateral purchase/sale contracts and to notify contractual parties of its actions in this regard no later than 5 days before the 1st day of the operating month.
3. The System Operator shall participate in development of all solutions regarding generation unit commitments, import and export opportunities for the wholesale power market.

7. Transmission constrains and transmission losses

7.1. Transmission constrains

1. Energy transmission within the transmission company boundaries is deemed to be constrained when due to the restrictions caused by requirements of safe, secure and reliable operation of the power system it is not possible to increase the power flows between certain parts of the transmission system beyond certain value which causes restrictions on the economic dispatch of the power system.
2. For each dispatch hour the System Operator shall register any effective constrains, including cause and duration of constrained condition.
3. All constrains that exist within the boundaries of transmission system shall be taken into account in the process of developing dispatch schedule and in real time dispatch.

7.2. Transmission losses

1. The issue of transmission losses should be reflected in the tariff for transmission services. ERA should establish the criteria for adjusting the transmission company tariff depending on transmission losses so as to provide incentive for Transmission Company to reduce the losses.
2. Transmission losses that take place when energy is transmitted from producers and importers to distribution companies are determined as a difference between the energy delivered to the boundary of transmission company (and therefore purchased by the distribution companies) and the energy delivered by transmission company to the boundaries of distribution companies.
3. The monthly losses calculated in accordance with Part 7.2.2 are compared with technically justified technological losses that are jointly established by the System Operator and

Transmission Company based on the variety of possible actual regimes of power system operation, and:

a. Regardless of the volume of energy delivered to the boundary of the distribution companies the distribution companies are responsible for paying for all energy that generation companies and importers delivered to the boundary of transmission company;
b. Distribution companies pay transmission company for transmission services pursuant to ERA approved tariff;
c. If in the given month actual average transmission losses exceed the maximum level of acceptable transmission losses defined pursuant to Part 7.2.3 the distribution companies payment obligations for transmission services are reduced by the cost of the energy that they had to purchase to cover excessive losses. The effective date for this provision may be set after some time since the market operation commences but no later than 1 year after commencement of market operation;
d. The amount of transmission losses refund due to individual distribution companies as a compensation for excessive transmission losses pursuant to Part 7.2.3(c) is calculated for each distribution company based on the average monthly energy cost of generation and importers as follows:

   TPR = (∑Gai*Wi)*Gd*(LFact-LFtj)/∑Gai, where

   TPR - transmission payment refund, $;

   Gai - the actual energy produced by the generation company "i" or importer and delivered to the transmission company boundary, MWHR;

   Wi - an energy component of the two-part tariff of the generation company "i" or importer, $/MWHR;

   Gd - the total actual energy for the month that was delivered to the distribution company by transmission company, MWHR;

   LFact - actual transmission loss factor for a given month;

   LFtj - technically justifiable transmission loss factor.

8. Planning of power system operating regimes

8.1. General provisions

1. The System Operator is an entity responsible for organization and coordination of power system operating regime planning activity. The regime planning is organized in a way as to allow market participants the greatest possible flexibility in a selection of their equipment, short and long term maintenance scheduling while maintaining safe and reliable operation of all elements of interconnected transmission network.
2. Criteria of optimal operating regime planning is a minimization of the total costs of electric energy provided for distribution companies.
3. The System Operator activities with regard to the operating regime's planning and to issuing recommendations and/or requirements to market participants to undertake certain actions for maintaining reliability should be guided by reliability and security of power

system operation rules contained in the Grid Code and adopted in Mongolian Power System.

8.2. Organizing of regime planning process

1. These market rules are specifying only the part of the System Operator activity regarding operating regimes planning that's connected with System Operator influence on commercial aspects and are not related to other aspects of the System Operator activities.
2. The System Operator's interaction with parties to bilateral purchase/sales contracts with regard to the power system operating regimes planning is conducted in a form of:
   a. Technical evaluation of bilateral contracts for purchase/sale of electric energy and capacity;
   b. Collection from market participants of:
      i) Information regarding parameters of generating equipment, including characteristics that reflect economic efficiency of generating units as described in Attachment , schedule of maintenance outages, schedules of power consumption;
      ii) Suggestions of market participants regarding maintenance schedule of all interconnected equipment, changes in transmission network parameters and topology, maintenance of relay protection systems that affects the limits of transmission lines transferring capability;
      iii) Other information that may be necessary for the System Operator;
3. Calculation of mid and short term power system's operating regimes and publishing reports that contain forecast of power system reliability parameters for each period;
4. Issuing recommendations to market participants regarding changes in bilateral contracts, plans for scheduled maintenance and conducting various activities associated with changing transmission network topology;

   and also if required – a full and unconditional compliance with the System Operator's instruction regarding maintenance of safe and reliable operation of the power system.

8.3. Technical evaluation of bilateral purchase/sale contracts

1. All bilateral contracts for purchase/sale of electric energy and capacity shall be agreed upon with the System Operator;
2. The agree upon procedure represent a technical evaluation of particular contract for purchase/sale of electric energy and capacity with regard to its consistency with reliability and security of power system operation criteria contained in the Grid Code and adopted in Mongolian Power System As a result of evaluation the System Operator may find that given contract is fully consistent with above criteria or to find it partially or fully inconsistent in which case the System Operator shall require changes to the contract that is necessary to bring it in the compliance with the above criteria.
3. All disputes which arise during agree upon process should be submitted to the reliability committee of stakeholder organization and if solution is not reached are further submitted to ERA for final decision.

8.4. Planning of the power system operating regimes and calculations of reliability indicators

1. Based upon the information collected from market participants the System Operator prepares power system short and mid term operating regimes and continuously performs monitoring of the power system reliability and regularly publishes forecast of the power system reliability indicators.
2. Operating regimes planning activity should be organized as a comprehensive program to collect information and develop short and mid term operating regimes which allows market participants to timely receive information that enables them to make decisions regarding their own market activity planning.
3. The System Operator shall to the best of its abilities provide market participants sufficient information with regard to possible problems that may impact the power system reliability so that market participants use this information in developing planned maintenance schedule without negatively impacting system availability.

8.5. Mid-term planning of power system operating regimes

1. Mid-term power system operating regimes planning covers 24 months period which is broken by months. Calculation of power system operating regimes is performed by the System Operator and results are published.
2. In case of significant changes the System Operator may publish additional adjusted results of regimes calculations.
3. The System Operator shall prepare the following input data to be used in the mid-term power system operating regimes calculations:
   a. Load forecast
      i) Which contains forecasted peak load of distribution companies, with the indication of peak time, monthly volume of consumed energy based on observed historic patterns and other related information; and
      ii) Contains approximate hourly profile for the typical day for each month of the year;
      iii) Forecast of import and export for each month of the year;
   b. Data regarding required capacity reserves;
   c. Forecast of system constrains known at the time.
4. Market participants shall provide the following input data for the mid-term power system regimes calculation:
   a. Producers – expected operational availability of each generating block, generation constrains, generation characteristics as described in Part 8.2.2(b)(i), maintenance schedule, suggestions with regard to providing ancillary services;
   b. Distribution companies – monthly consumption schedules;
   c. Exporters and importers – daily and hourly schedules of export/import for the typical days of the month;

d. Transmission company – proposed schedules of planned maintenance of transmission equipment, expected changes in transmission network topology, thermal line transferring capabilities, suggestions with regard to providing ancillary services;

5. For each month of the covered mid-term regimes planning period the System Operator shall prepare and publish report containing:
   a. Schedules of planned maintenance of generating, transmission and distribution equipment;
   b. Peak load and energy forecasts for the power system;
   c. Required capacity reserves;
   d. Combined operational availability of generating capacity;
   e. Description and qualitative estimate of:
      i) Any forecasted violations of the power system reliability;
      ii) Specific months where there expected to be low capacity reserves or reserve deficiency;
      iii) Forecast of the transferring capability of interconnection ties ; and
      iv) Time periods and transmission system localities, if any, where system constrains may impact economic dispatch.
6. The System Operator shall develop a document that contains procedure for mid-term power system operating regimes planning and to distribute this document among market participants.

8.6. Short-term planning of power system operating regimes

1. The short term calculations of the power system operating regimes are conducted by the System Operator on a daily basis.
2. The short-term calculations cover the period of 7 days broken by hours.
3. To perform the short term operating regimes calculations the System Operator shall use the following input data:
   a. The hourly load forecast for each day;
   b. Necessary additional capacity reserves;
   c. Expected transmission constrains known to the system operator at the time.
4. Market participants shall provide the following input data for the short term power system regimes calculation:
   a. Producers – expected operational availability of each generating block, generation constrains, generation characteristics as described in Part 8.2.2(b)(i), maintenance schedule, suggestions with regard to providing ancillary services;
   b. Distribution companies – hourly consumption schedules for each day;
   c. Exporters and importers – daily and hourly schedules of export/import for the typical days of the week;

d. Transmission company – proposed schedules of planned maintenance of transmission equipment, expected changes in transmission network topology, thermal line transferring capabilities, suggestions with regard to providing ancillary services;

5. For each day of the covered short term regimes planning period the System Operator shall prepare and publish report containing:
   a. Schedules of planned maintenance of generating, transmission and distribution equipment;
   b. Peak load and energy forecasts for the power system;
   c. Required capacity reserves;
   d. Combined operational availability of generating capacity;
   e. Description and qualitative estimate of:
      (1) Any forecasted violations of the power system reliability;
      (2) Specific hours where there expected to be low capacity reserves or reserve deficiency;
      (3) Forecast of the transferring capability of interconnection ties ; and
         i) Time periods and transmission system localities where system constrains may impact economic dispatch.
6. The System Operator shall develop a document that contains procedure for short term power system operating regimes planning and to distribute this document among market participants.

8.7. Dispatch hour

1. The dispatch hour represents a dispatch interval of 60 minutes duration.
2. The dispatch hour is defined by its ending hour.
3. The dispatch (operating) day includes 24 consecutive dispatch hours and ends at 23:59:59.

9. The System Operator daily activities in market operation

9.1. Dispatch process organization

1. The System Operator is responsible to perform the dispatch of generating equipment including equipment that is a party to bilateral purchase/sale contracts to balance the power system demand and supply while maintaining power system reliability and security.
2. The goal of the dispatch process is to minimize the cost of the produced energy while taking into account:
   a. Constrains associated with generating units availability and unit commitment;
   b. Constrains that are established for the reason to maintain reserves;
   c. Transmission constrains and transmission losses;
   d. Constrains on interconnection ties.

3. From time to time the System Operator shall investigate possibility of further development of dispatch process and to prepare recommendations to be included to its annual report to ERA regarding market operation.

9.2. Preliminary dispatch schedule

1. The System Operator shall on a daily basis prepare and notify generation companies of preliminary dispatch schedule which includes each dispatch hour for the next dispatch day.
2. The input for the development of preliminary dispatch schedule is an information prepared in the process of short term regimes planning. The prepared preliminary dispatch schedule should be developed by centrally dispatching, to the extent that heating requirements and power system constrains allow, the more efficient generation first and minimizing the total cost of production of energy for the planning period.
3. Each producer that is included in the preliminary dispatch schedule shall ensure that it is able to work in the regime that is envisioned by the dispatch schedule.
4. The System Operator shall communicate to the generation company that are part of the preliminary dispatch schedule the following data, preferably electronically:
   a. Planned hourly loading level of each generating unit included in the preliminary dispatch schedule;
   b. Planned providing of ancillary services;
   c. Planned restrictions caused by the transmission constrains.

9.3. Participation in the development of preliminary dispatch schedule

1. In addition to the information communicated to the System Operator pursuant to Part 8.6.4 all market participants two days before the new dispatch day shall notify the System Operator of actual equipment availability and generation units constrains.
2. If there is no additional information the System Operator shall use the latest available data that were included in short term operating regimes calculations.

9.4. Availability verification tests

Availability verification tests and capacity audits shall be conducted by the System Operator in accordance with ERA approved guidelines as specified in Part 5.1 of these rules.

9.5. Transmission constrains

1. The System Operator is responsible for determining transmission constrains that may exist due to the planned and unplanned line disconnections and which may impact dispatch of generating capacity.
2. The System Operator shall inform the market participants about transmission constrains that were used as an input to the dispatch process in such form that they could be analyzed after the end of the dispatch hour during which these constrains existed.

9.6. Dispatch process in real time

1. Generation capacity and customer's load should be centrally dispatched by the System Operator using preliminary dispatch schedule.

2. It is preferred that dispatch instructions should be communicated electronically, however until such capabilities are available the System Operator may issue dispatch instructions via telephone with mandatory logging of every communicated dispatch instruction in a special log maintained in the dispatch center control room.
3. Market participants must be in possession of the special equipment to receive dispatch instructions. All dispatch instructions received by market participants should be registered and maintained in a special logbook.
4. The preliminary dispatch schedule may be changed by the System Operator only for reason of maintaining power system reliability and/or security or for the reasons of sudden outage of generating units or non-compliance of generating unit with dispatch instructions. In these cases the System Operator should prepare a detailed explanation of reason(s) for deviation from the preliminary dispatch schedule.

9.7. Dispatch under capacity deficiency conditions

If there is capacity deficiency the System Operator must ensure that the following actions are taken:

1. If there is a generation capacity committed to export all export supplies have to be curtailed and respective generation capacity used to satisfy demand of internal customers.
2. All generation resources should be dispatched utilizing their maximum capability while taking into account power system security requirements.
3. Public appeal should be issued to ask customers to curtail to the extent possible consumption of electricity.
4. Agreed upon in advance schedule by System Operator and distribution companies schedule of load restriction and curtailment must be implemented.
5. All necessary actions should be undertaken in accordance with rules to assure system reliability to rectify the situation.

9.8. Failure to comply with dispatch instructions

1. If during certain time period defined by the System Operator, an operator of the generating block which is included in the preliminary dispatch schedule does not comply with the dispatch command issued by the System Operator, the System Operator:
   a. Contacts the operator of a non-compliant generating block and demands the explanation of reasons for non-compliance and orders remedial actions and if this doesn't remedy the situation;
   b. Declares that this generating block is a violator of dispatch discipline;
   c. Makes a recommendation to apply to the violator the punitive sanctions for the sited violation in accordance with violator's license provisions.
2. If there is a declaration that certain generating block is a violator of a dispatch discipline the System Operator can undertake the following additional actions:

a. System Operator may request that operator of the generating block submit corrected parameters of respective equipment so that System Operator could continue the execution of dispatch schedule.

b. If the operator of the generating block does not comply with provision of Part 9.8.2(a) or if the System Operator is not convinced that the generating block could comply with dispatch instructions as required, the System Operator may directly intervene and issue an order to maintain the block's generation output at the level fixed by the System Operator.

3. Until the time that violator complies with provisions of Part 9.8.2(a) and 9.8.2(b) and until the System Operator is not convinced that dispatch instructions are followed as required the generating unit is still considered to be a violator.

4. If after certain time period the generating unit still remains a violator the System Operator shall prepare a document containing detailed description of circumstances associated with the violation and to notify violator's contractual parties and the ERA about the violation.

10. Ancillary technological services

10.1. Introduction

1. Ancillary technological services are the services that need to be provided system wide rather than to individual entities in order to provide for the reliable and safe operation of the power system and to assure acceptable quality of power supply. While various ancillary services can be provided by various entities there is no individual beneficiaries of these services. The entire community of power system users is the beneficiary of the power system. The power system dispatch and transmission services are examples of most important technological ancillary services. The other most common technological ancillary services are:

   a. Providing of secondary frequency regulation and load following capability – supplied by generators and in Mongolia conditions also by import from Russia.

   b. Ensuring sufficient amount of operating reserve capacity in accordance with the rules for reliable and safe operation of the power system – supplied by generators, dispatchable and interruptible load, if any, and in Mongolia conditions also by import from Russia.

   c. Voltage regulation by regulating production and consumption of reactive power – provided by Transmission Company, generators, distribution companies, large consumers.

   d. Participation of generators and large consumers in operation of special protection systems.

   e. "Black start" capability – participating in the power system restoration after its collapse by providing capability for generating unit to start-up without an autonomous source of energy in order to directly energize another generator or to supply energy to the grid – provided by certain generators, in Mongolia conditions- by import from Russia.

2. Requirements with regard to procurement of technological ancillary services have to be satisfied as follows:

a. The System Operator sets the minimum level of technical requirements to be maintained in the process of power system operation compliance with which requires providing of a certain level of ancillary services.

b. Requirements established by the System Operator in accordance with Part 10.1.2(a) shall be reflected in the interconnection procedures and/or in bilateral contracts.

3. The System Operator during the first year of the market operation shall conduct research and consultations with market participants and at the end of the first year of market operation to submit to ERA report regarding possible development of competitive or regulatory mechanisms to procure ancillary services.

10.2. Provision of technological ancillary services

1. Market participants provide technological ancillary services by executing respective specific dispatch instructions of the System Operator.
2. Market participant can not refuse without the valid reason to provide the ancillary service requested by the System Operator.
3. The System Operator in order to secure safe and reliable operation of the power system is authorized to issue instruction to any market participant to provide an ancillary service if that market participant operates equipment that is capable of doing it.

10.3. Testing of availability to provide technological ancillary services

The System Operator in consultation with market participants organization shall develop a procedure to conduct a periodic testing of the power system equipment in order to test and verify the ability of respective equipment to provide specific ancillary services.

11. Market related information

11.1. Provision of information

1. The System Operator in consultation with ERA and market stakeholders organization shall define the volume, specific responsibilities and authority of the System Operator regarding publishing of market related information.
2. The System Operator in consultation with ERA and market stakeholders organization shall developed the guidelines of classifying certain information as confidential and/or commercially protected.
3. The System Operator shall secure an open access to the market related information that is not classified as confidential and/or commercially protected in accordance with Part 11.1.2, and to develop a procedure to assure the confidentiality of information that is classified in accordance with Part 11.1.2 as confidential and/or commercially protected.

11.2. Mechanism and the order of submittal of information

1. Information from market participants to the System Operator and from the System Operator shall be provided electronically unless the System Operator defines an alternate order of providing the information.

2. Information shall be submitted using specific formats developed by the System Operator unless other format is agreed upon with participant and the System Operator.
3. Information received by the System Information must have a time mark of the time it was received.
4. The System Information shall keep all copies regarding all data changes it distributes to the market participants for verification and if necessary for subsequent distribution.
5. All amended data shall be provided in the same format as initial data.
6. The market participant can not refuse to provide to the System Operator an information which otherwise has to be provided in accordance with these market rules without specific permission from ERA unless ERA at participants request finds that:
   a. The information is confidential or reflects commercially sensitive trends and at the same time in ERA's opinion is not absolutely necessary for the efficient operation of the power market; or
   b. Disclosure of the information may cause the financial damage to the entity, that is requested to provide the information. Nevertheless ERA may order release of the information if in its opinion the value of this information to community exceeds the possible damage.
7. None of the provisions of Part 11.2.6 allows market participant to refuse to provide an information to the System Operator in accordance with provisions of these rules if such information is publicly available elsewhere.

11.3. Permanent data

1. The System Operator shall receive, maintain, correct and publish:
   a. The list of all market participants and list of all applications to become a market participant;
   b. The list of all entities that ceased to be market participants and a date when these entities ceased to be a market participants;
   c. The list of all market participants whose market activity had been or about to be suspended with an indication of reasons for such suspension and the dates the suspension took place or is expected to take place.
2. All producers are required to provide the System Operator with characteristics of the generating units that they operate in accordance with Attachment 1.
3. All market participants are required to provide the System Operator settlement department the information listed below:
   a. Forecast of new points of interconnections to the transmission system;
   b. The metering information required to conduct settlement activity;
4. The transmission company shall maintain the list of received applications for interconnection and to provide it to the System Operator at System Operator's request.
5. Each year by the time specified by the System Operator the transmission company shall provide to the System Operator and ERA the following information:

a. Expected transferring capability of transmission lines under normal and emergency modes of operation;
b. Electrical characteristics sufficient to model power system operation under the static and dynamic modes.

6. The transmission company shall as soon as possible notify the System Operator and ERA of all changes in the information provided in accordance with Part 11.3.5.
7. In order to facilitate efficient dispatch of the power system market participants shall notify the System Operator of all changes in characteristics that may impact the economic dispatch of generating resources without undue delay.

11.4. Market audits

1. The ERA in consultation with the market stakeholder organization and the System Operator shall initiate and organize the market audit and if necessary attract independent experts/consultants as an Auditor. The goals of the audit are following:
   a. Analysis of correctness of calculations performed on the basis of data provided by metering systems;
   b. Analysis of correctness of informational and billing systems;
   c. Analysis of the processes of development of preliminary dispatch schedule and conducting a real time dispatch;
   d. Analysis of utilization of IT resources;
   e. Analysis of the actions of the System Operator with regard to compliance with provisions of market rules.
2. In the process of conducting the audit the Auditor shall periodically inform ERA and market participants of intermediate results.
3. Upon the completion of audit and review by the System Operator the audit should be submitted to ERA and market participants

12. Force majeure

12.1. Force majuere circumstances

1. Upon conducting consultations with market participants' planning and reliability committee the System Operator shall develop and submit for ERA's approval the guidelines for actions under the force majeure conditions, that contain:
   a. The definition of force majeure circumstances;
   b. Description of actions of the System Operator, Transmission Company and commercial market participants and ERA and other concerned government authorities regarding operation of the wholesale power market.
2. Force majeure guidelines may contain provisions authorizing the System Operator to suspend activities under the market rules;
3. The System Operator must immediately notify all market participants and stakeholders about creation of force majeure circumstances.

Attachment 1: Registered characteristics of market participants' equipment

Registered characteristics of market participants' equipment is a standard set of data that are necessary to develop dispatch schedules to cover demand during the dispatch day. Market participants are required to provide the registered characteristics for each generating unit that they operate or for each dispatchable load in accordance with this Attachment no later that 6 weeks before commencement of their market activity.

Market participants are required to review the registered characteristics of equipment they operate semi-annually and to provide the System Operator detailed information regarding any changes in registered characteristics.

Registered characteristics may be adjusted by market participant at any time and also can be tested and/or verified at any time upon request of the System Operator.

If required copies of all changes may be returned to market participant for verification with subsequent repeated submittal to the System Operator.

Generating unit data

Data	Units
Power plant information:	
Plant name or ID number	
Total installed nameplate capacity	MW
Total net available capacity (less own usage)	
Daily energy production limitations (if any)	MWHR/day
Generating unit information:	
Full available capability	MW
Technical minimum load	MW
Maximum capability to be available under emergency conditions	MW
Ramping rate:	
Up	MW/Minute
Down	MW/Minute
Time to reach full load from cold condition	Hours
Time to reach full load from hot condition	Hours
Shut down time cold start applies	Hours
Shut down time hot start applies	Hours
Notice to start	Hours
Minimum run time	Hours
Minimum shut down time	Hours
Generating units thermal efficiency characteristics (as applicable these parameters should be identified separately for operation in heating and condensing modes respectively).	
Average full load heat rate	Grams of conditional fuel/KWHR

Data	Units
Heat input at minimum load	Tons of conditional fuel
Incremental heat rates:	
Load block 1	Grams of conditional fuel/KWHR
Load block 2	Grams of conditional fuel/KWHR
Load block 3	Grams of conditional fuel/KWHR
Load block 4	Grams of conditional fuel/KWHR
Cold Start Heat Input	Tons of conditional fuel
Hot Start Heat Input	Tons of conditional fuel
Cold start fixed cost	$
Hot Start fixed cost	$

Dispatchable load data

Data	Units
Name or ID number	
Normally On/Off	
Maximum load	MW
Daily energy limitations	MWHR/Day

Attachment 2: Procedure for calculation of availability factors for generating units

It is proposed in the market rules that monthly capacity payments calculation under bilateral contracts take into account generating units' availability factors excluding planned outages as follows:

CP = CR*AFc*CT/12, where

CP - capacity payment, $
CR - unit rated capacity, MW
CT - capacity component of 2-part tariff, $/MW-year
AFc - adjusted unit availability factor, (0<AFc<1), reflecting availability of a given generating unit/plant as it compares to established benchmark.

Generally availability factor AF for a specific period (year, month) is normally calculated by following formula:

AF = (1 – SOd/D)*(1-EFOR), where

Sod - number of days on planned scheduled outage, usually SOd = n*7+2, where n-number of weeks, scheduled for planned outage, i.e. outage reflected in an annual outage schedule developed by the System Operator in accordance with Operation Procedure No.5;
D - number of days in a period;
EFOR - effective forced outage rate in a period, (0<EFOR<1). Unit considered to be forced out if they are not available while not on planned outage.

Effective forced outage rate should account for both: full and partial outages/capacity reductions.

For the purpose of calculating availability factors to be used in conjunction with bilateral contracts the planned outages should be ignored, i.e. availability factors should be calculated excluding the time unit is on planned outage. However if the duration of a planned outage exceed the time normally allowed for the planned outage, the excessive time should not be qualified as a planned outage and should be treated as a forced outage.

So for the use in conjunction with bilateral contracts availability factors should be calculated as follows:

AFi = 1-EFOR, where AF is availability factor for unit "I" that doesn't reflect time while unit is on planned outage.

EFOR for a specific generating unit can be calculated as follows:

EFOR = (CR*HRf + (∑CRpri*HRi))/CR*HRS, where
HRf - number of hours during which full unit's rated capacity is not available while unit is not on planned outage;
CRpr - amount of reduction in rated capacity for each incident of reduction, MW;
HR - duration of each incident of reduction, hours.

Effective forced outage rate for the entire power system generation capacity can be calculated as follows:

EFORps = (CRT*HRf + (∑CRTpri*HRi))/CRT*HRS, where

CRT = Total rated capacity of entire power system, CRT = ∑CRi, MW;

or EFORps may be calculated as follows:

EFORps = ∑EFORi*CRi/∑CRi, where

EFORi, CRi are effective forced outage rates and capacity rating of each individual units.

After a sufficient (statistically representative) volume of availability related data is available, the System Operator calculates AFi (availability factor for individual unit) and AFps (availability factor for the power system generation) as follows:

AFi = 1- EFORi, and
AFps = 1- EFORps.

The value of AFps may serve as an established benchmark capacity for the combined power system generation.

Unforced rated capacity for generating unit/plant "I" CRU may be calculated as:

CRUi = CR*AFi/AFps,

Beginning with a certain date, established by ERA the capacity payments under bilateral contracts "CP" should be calculated as follows:

CP = CR*(AFi/AFps)*CT/12.

In this way the generating unit/plant with availability above the benchmark will receive the higher payments (bonus) while the unit/plant with availability below the benchmark will receive lower payments (penalty).

Alternatively bilateral contracts may reflect unforced rated capacity CRU rather than rated capacity CR.

Please note that information contained in this Attachment is advisory. The actual formula for capacity payments should be determined by the terms of bilateral contract and may or may not employ different approach to reflect generating units availability.

SECTION VI: OPERATIONAL PROCEDURES FOR MARKET IMPLEMENTATION

1. *Operating procedure No.1:* Operating responsibility and authority of the System Operator

Introduction

The System Operator is responsible to serve as the operator of the Central Interconnection of Mongolian National Electric Power System (subsequently the power system) and as administrator of the wholesale power market. It fulfills its responsibilities consistent with the terms of all applicable laws and regulations.

This Operating Procedure defines the overall parameters within which the more specific operating procedures can be formulated.

Principles

The System Operator is responsible for the day-to-day operation of the Mongolia power system resources in accordance with all applicable rules and procedures.

To most efficiently achieve the objective of central dispatch, it is necessary that the System Operator and other market participants execute their responsibilities with a spirit of cooperation and with an understanding of the tasks to be accomplished.

General Statement of Responsibilities

The System Operator is responsible in matters pertaining to the central dispatch of all transmission facilities rated 110kV and above, dispatchable load and all generating resources, including imported power, committed to Central Dispatch.

This assigned responsibility and authority extends to include decisions, instructions, and orders issued to market participants electronically, verbally or in writing, as required for day-to-day, minute-to-minute operation of both generation and transmission facilities.

Participant's facilities will also contribute to Central Dispatch in accordance with approved wholesale power market rules and all other applicable regulations.

The System Operator and all other market participants share a responsibility to initiate dispatch actions deemed necessary to prevent injury, loss of life, equipment damage, and/or service interruptions.

Consistent with the general responsibilities stated within this procedure and to assure the effectiveness of Central Dispatch through the System Operator and other market participant facilities, the following dispatch assignments are made. The listed assignments include most of the fundamental responsibilities of central dispatch. It is expected that these responsibilities will receive continual review and will be updated as needed to assure efficient operation of the Mongolian power system. It is further understood that all operating entities at the System Operator and all other market participant level share a responsibility to protect proprietary and privileged information that may unduly influence the operation of the wholesale power market.

1. **Transmission Operation**

    a. Monitor power flows on all transmission facilities operating at 110kV and above.

b. Initiate central dispatch actions, including the commitment and/or decommitment of generating units and MW adjustment of power resources, required to insure that the facilities noted in (1(a)) above are operated in compliance with all relevant rules and procedures.
c. Coordinate voltage control and reactive dispatch of transmission facilities.
d. Respond to system disturbances by initiating load management procedures, including voltage reduction and load shedding.
e. Coordinate system restoration after wide spread loss of load.
f. Direct implementation of voltage reduction procedures as necessary.
g. Implementation of load shedding and system restoration procedures.

2. Security Analysis

a. Schedule outage for transmission facilities operating at 110kV and above (and relevant 35kV facilities) based on contingency analysis that will assure reliable operation.
b. Schedule outage for maintenance of communications, computers, metering and support equipment (Operating Procedure No.2) based upon projected system conditions.
c. Monitor power flows on transmission facilities operating at 110kV and above. Based on contingency analysis initiate appropriate dispatch actions to assure reliable system operation.
d. Schedule and administer long and short-term maintenance.

3. Economic Dispatch of POWER SYSTEM

a. Continuously monitor the power resource loading conditions and determine the most economical allocation of power resources, taking into account Mongolia system load, reserve, reliability, and other power system specific requirements.

4. Automatic Generation Control (AGC)

(For the future Mongolia Power System development)

a. Maintain a sufficient number of generating units on AGC to satisfy reliability, economic and tie line regulation requirements. Units on AGC should be selected to achieve the best economics while maintaining system reliability and/or control performance.

5. Control Area Interchange and interconnection Scheduling

a. Schedule, monitor, and maintain the System Operator Control Area interchange with Russia while adhering to all related operating criteria.
b. Forecast inter-area exchanges, consistent with scheduling periods, (hourly, weekly, and monthly) to be used as delimiters in the scheduling of inter-area transfers.
c. Develop and/or coordinate hourly, weekly, monthly, etc. interchange schedules for all interchange arrangements between and/or through Mongolia power system participants and neighboring power systems (Russia), including emergency transactions.
d. Incorporate appropriate scheduled power contracts into the daily commitment process and communicate to all necessary external parties.

e. Maintain a record by contract of interchange activity.

6. Contract Administration

a. Monitor, schedule for delivery, and/or suspend available power contracts within Mongolia power system and external contracts based upon contract availability criteria, the optimization of system economics and/or system reliability constraints.

7. Maintenance Coordination - Generation

a. Receive, recommend approval/disapproval and administer requests for long and short-term maintenance.

8. Generator Tests and Audits

a. Initiate and administer parameter audits on participants' generating units in accordance with specially developed procedures.
b. Give authorization for participants' initiated demonstrations.

9. Operating Reserve

a. Maintain a sufficient amount of operating reserve. If available capacity is insufficient to provide adequate operating reserve, the System Operator will implement the following procedures:

   Operating Procedure No.7 – Operating Reserve
   Operating Procedure No.4 - Actions Under Capacity Deficiency Conditions
   Operating Procedure No.9 - Actions Under Emergency Conditions

10. System Load Forecasting

a. Forecast and update the present day's forecast for the power system hourly loads to be used in generating unit commitment and power contracts.

11. Generating Unit Commitment

a. Develop commitment/de-commitment schedules for all power resources available for central dispatch with consideration for system security and reliability constraints.
b. Communicate to participant the most current commitment/de-commitment schedules.
c. Coordinate activities between the System Operator and participant personnel on matters related to the operation of the participant power resources.
d. Coordinate participants recommend changes to commitment or incremental loading of power resources to maintain area voltage and/or to meet thermal transmission requirements.

12. Generating Unit Control Modes and Operating Limits

a. Maintain the status of all power resource control modes and operating limits on all generating units under the System Operator direct control.

b. Maintain operating parameters, such as minimum run times, minimum down times, response rates, etc. of all System Operator Participant power resources via the System Operator communication system.
c. Compile and maintain all necessary information required by System Operator Settlements Center for resources under the System Operator's direct control.
d. Incorporate known generator operating restrictions into security analysis.
e. Report all necessary information to reflect all generating units redeclarations.

13. System Operator Backup Facilities

a. Develop and implement a back-up plan for all functions for which the System Operator is responsible including all necessary software, hardware and facility requirements.

14. Communication - Data

a. Maintain all dispatch related data in a secure database(s) for at least 2 years.
b. Collect from participants real-time data required to perform central dispatch functions. Operating Procedure No.16 - Metering and Telemetering Criteria defines specific requirements.

15. Communication - Voice

a. Provide the necessary voice communications required to issue central dispatch instructions directly to generating stations, units and power resources including recording and maintaining records in a secure database(s) for at least 2 years.

16. Dispatch Computers and Peripheral Dispatch Equipment

a. Be responsible for scheduling and coordinating planned outages of the System Operator computers, data and voice communication networks and any other related equipment that is used by the System Operator. This is further defined in Operational Procedure No.2 – Requirements for Communications, Computers and Metering.

2. *Operating procedure No.2:* Maintenance of communications, computers, and metering equipment

Introduction

This procedure establishes criteria for the repair and maintenance of equipment loss of which may have a significant impact on the ability to reliably operate the power system.

The following lists types of equipment which depending on specific roles can be critical to system operation:

- Computers
- Metering, Telemetering and Control equipment
- Communication equipment
- Computer support equipment
- Associated equipment

While it is impossible to list all the conceivable contingencies that might result in failure of critical equipment, this instruction attempts to identify the equipment and give guidelines for its repair or maintenance.

This procedure includes provisions for allowing warranted exceptions to the established maintenance priorities for the covered equipment.

Scope

This procedure covers all equipment located at System Operator premises.

In order to promote efficient and rapid repair or maintenance of affected equipment, the following aspects of repair and maintenance work are covered:

- Criteria for repair/maintenance priority
- Establishment of Criteria
- Responsibility for repair/maintenance
- Scheduling of routine maintenance
- Day of performance of routine and emergency/unplanned maintenance
- Record keeping

Procedure

1. Criteria for Repair/Maintenance (Priority)

The following criteria identify required response times to begin repair of failed equipment. The times are based upon the importance of the equipment to system operations. This same criterion is used to prioritize requests made for equipment maintenance.

A. Immediate

This highest priority for repair or maintenance applies to equipment that is critical to maintain adequate system security and reasonable economic dispatch.

B. Regular - working hours weekdays

This intermediate priority is intended for equipment whose loss can be tolerated for limited periods of time, but which cannot or should not be tolerated for prolonged periods of time.

2. Establishment of Criteria

A. Under normal conditions

The criteria (priority classification) for maintenance of various equipment affecting System Operator operation should be followed.

B. Under abnormal conditions

The System Operator control room staff has the authority and responsibility to change the established criteria. If a criterion is changed, the operator requesting the change must document it.

3. Responsibility for Repair/Maintenance

A. Assignment of Repair/Maintenance Responsibility

The location of the equipment in most instances establishes the responsibility for repair or maintenance. Repair or maintenance of facilities and/or equipment used in support of the System Operator activities but not owned by the System Operator shall be the responsibility of the owner.

B. Repair Work

Response to reports of equipment failures must be within the time requirements proscribed in Part 1of this Section. Repair work status should be communicated among all effected parties.

C. Coordination of Maintenance

It is the responsibility of the System Operator to coordinate all equipment maintenance. Coordination includes the scheduling, approval or denial of requests for regular maintenance, and the change in criteria classification in the event of emergency.

4. Scheduling of Routine Maintenance

Requests for arranging advance schedules for routine maintenance of any equipment that is not owned by the System Operator but is used by it in the course of performing its duties should be submitted by owners/operators of this equipment to the System Operator.

5. Record keeping

It is the responsibility of the System Operator to perform record keeping necessary under this procedure as required by each location.

Attachment

Maintenance of Communications, Computers, Metering and Building Services

System Operator Computer Equipment:	Maintenance Priority
Any equipment or device that may interrupt or alter the flow of data critical to system operation	
Not supported by a back-up system	A
Supported by a back-up system	B
Control Room Printers and Loggers	B
Other Equipment at System Operator facility	
Fire Protection System	A
Un-interruptible Power Supply (UPS)	A
Frequency Measuring	B
Security System	B
Diagram Board Displays	B
Recorder Panel (Including Digital Displays and Clock)	A
Telephone Message Recorders	A
Voice Communications	
Dispatcher telephone circuit	A
Control Room direct dial outside lines	A
Administrative telephone circuits	B
Control, Telemetering, and Data Communications	
Data Links - System Operator Centers	A
System Operator tie line telemetering – primary circuit	A
System Operator tie line telemetering – secondary circuit	B
Weather services system	B
Communications channels for special protection systems	A
Remote terminal units and communication	A

Maintenance of equipment not specifically mentioned in this procedure will be handled on a case by case basis by the staff of the System Operator.

3. *Operating procedure No.3:* Transmission maintenance scheduling for facilities operating at 110kV and above

Introduction

Transmission maintenance must be coordinated between Transmission Company and the System Operator to ensure that reliability is maintained at levels prescribed by the Grid Code of the Mongolian Power System. Operating problems due to maintenance outages must be thoroughly studied. Transmission and generator maintenance must be coordinated to avoid deterioration of reliability.

Authority

The System Operator has the responsibility of evaluating, approving or disapproving outage schedules for all transmission facilities rated 110kV and above and selected 35kV facilities that are considered as a part of transmission system.

Purpose and Scope of Procedure

The purpose of this procedure is to achieve the following:

a. To facilitate the long-term planning of maintenance outages of Mongolia transmission facilities
b. To establish a short-term outage scheduling process that does not jeopardize the reliability of the transmission system
c. To provide guidelines for responding to emergency outages

The following definitions are used in this procedure:

a. **Long-term maintenance outage plans** are rolling projections of transmission outages for future periods. The plans are established quarterly.
b. **Short-term maintenance outage schedules** are specific schedules for upcoming outages.
c. An **Emergency Outage** is any outage that fails to satisfy the lead times necessary to fully study the implications of the outage on power system operation as required for the short-term maintenance schedule.

1. Long Term Outage Plans

This part describes the process for establishing and maintaining long-term outage plans.

Preparation/Update of Long Term Plan

The System Operator will maintain a long-term transmission overhaul and maintenance schedule on a rolling basis, which looks out at least twelve months. The schedule will be updated every quarter to incorporate the following information:

a. newly submitted or revised requests for transmission outages
b. adjustments to previously submitted requests made by the System Operator (working with the participants) for system reliability

Scope of Long-term Outage Plan

The schedule will include planned outages of all transmission lines and associated equipment operating at 110kV and above and selected 35kV facilities that are part of transmission system. Outage of any associated equipment must be reported even though the line itself may remain in service.

System Operator Responsibilities

The System Operator will assign a date-stamp to each maintenance request. The date stamp will be used, if needed, to prioritize outage requests. If the participant requests a change in the date of the outage for the long term plan, the System Operator will assign a new date stamp to the outage.

The System Operator staff will conduct reliability impact check for each requested outage in order to determine the feasibility of performing maintenance in the requested time period, taking into account load projections, generator maintenance schedule, and previously scheduled transmission outages. If the System Operator staff determines that there is a conflict, they will work with the participants requesting the outages to identify an acceptable time period for the outage.

2. Short Term Outage Scheduling

The participant wishing to do work on facilities covered by this procedure will submit a completed application form to the System Operator. The System Operator will review applications for work on transmission facilities. Outages of transmission facilities may require extensive study and coordination by the System Operator to ensure that operations are within prescribed reliability criteria. Participants must coordinate equipment and manpower needed to do the work.

To provide adequate time for this analysis and coordination the System Operator response times will be established. Outage schedule must be acted upon in a timely manner by the System Operator to provide participants with adequate lead times.

When the review and reliability study has been completed, the System Operator will communicate its conclusions to the appropriate participants.

3. Emergency Outages

An Emergency Outage is any outage that fails to satisfy the lead times as identified in previous part.

There are two types of emergency outages:

a. The obvious failure of a piece of transmission equipment that comes out of service on its own or requires immediate operator intervention to remove it from service.
b. The discovery of a problem that needs to be repaired as soon as crews, equipment, and/or corrective dispatch actions can be put in place to allow the work to be performed.

Requests for emergency outages of transmission facilities should be submitted to the System Operator immediately upon discovery of the problem.

4. *Operating procedure No.4:* Action during capacity deficiency

Introduction

This procedure establishes criteria and guidelines for actions during capacity deficiencies and is implemented by the System Operator in coordination with all market participants. This procedure may be implemented any time when one or more of the following events, or other similar events, occur or are expected to occur:

a. available power system resources are insufficient to meet the anticipated load plus operating reserve requirements;
b. transmission facilities into a subarea of the power system are loaded beyond established transfer capabilities;
c. a subarea of the power system is experiencing abnormal voltage and/or reactive power conditions.

Procedure

The System Operator shall promptly alert the participants any time one or more of the above conditions are anticipated, or have actually been experienced. The alert will be issued. Upon implementation, the System Operator will notify the participants of the actions required. The necessary actions will be initiated in accordance with this document and market rules. The System Operator may dispatch power resources as required to ensure reliability.

(The actions will be developed in the future)

Cancellation of Actions

When the system conditions have improved sufficiently, the System Operator will cancel the instituted actions.

Communications with Participants

The System Operator control room staff will use the "party line" telephone circuit to implement this procedure. The System Operator will briefly inform all participants simultaneously of system conditions and issue an implementation message.

5. *Operating procedure No.5:* Generation maintenance and outage scheduling

Introduction

All generating units are to be maintained in accordance with good maintenance practices. To the extent possible, maintenance and outage requirements should be met by planning to prevent forced outages and by coordinating known outage requirements through the System Operator. Units should not be operated without maintenance to the extent that they are forced out of service and then maintained.

All generator maintenance and economic outages are to be scheduled in accordance with this procedure. Generating units should not be taken out of service for maintenance without System Operator approval, unless there is danger to personnel or risk of equipment damage. If a generating unit is forced out of service due to personnel or equipment risk, the System Operator generation coordinator/forecaster and control room must be notified as soon as practicable.

This procedure defines the process for requesting, evaluating, and either approving or denying generator unit maintenance and economic outages.

The four maintenance outage-scheduling processes are:

1. The First Future Year - Maintenance and Outage Schedule
2. The Current Year - Maintenance and Outage Schedule
3. The Outage Request
4. The Short Notice Outage Request

This procedure is designed to facilitate each Participant's maintenance and outage scheduling.

The scheduling requirements are designed to allow

a. sufficient time for Participants to respond to the market's needs, and
b. sufficient time for the System Operator to assess the impact of each generator's outage request on Mongolia's bulk power system reliability.

This procedure includes definitions of key terms, responsibilities of Participants, System Operator, as well as rules for outage evaluation.

Definitions

1. **"Planned Outage" -** Planned outage means an outage which is scheduled in advance and is of predetermined duration, usually lasting for two weeks or more, and typically occurs once or twice per year. These outages are initially coordinated in the First Future Year - Maintenance and Outage Schedule.

2. **"Maintenance Outage" -** Medium notice maintenance outage means an outage which can be deferred beyond the 15 day window for short notice outage requests, but requires that the unit be removed from service before the next Planned Outage. These outages are generally coordinated in the Current Year - Maintenance and Outage Schedule.

3. "**Short Notice Outage" -** Short notice outage means an outage requiring the removal of a unit from service within the next 15 days and whose duration is less than 15 days. These outages are coordinated through the Short Notice Outage request.

4. **"Forced Outage" -** Forced outage means an unanticipated outage that requires the removal of a unit from service either immediately or with relatively short notice, due to unexpected maintenance where lack of attention could cause danger to personnel or risk of equipment damage. These unplanned outages do not require a Short Notice Outage Request. A Forced Outage does require the notification of the System Operator generation coordinator/forecaster and the control room as soon as practicable.
5. **"Economic Outage" -** Economic outage means the removal of a unit from service for economic reasons based on a Participant's request consistent with Market Rules and Procedures. Participants may make decisions affecting the availability of a unit for reasons relating to the economics of operating that unit. Participants are expected to act in accordance with the applicable provisions of the Market Rules and Procedures, which provide for the coordination required to minimize the impact of unit unavailability on short term system reliability. These outages shall be coordinated through the Short Notice Outage Request, but these requests cannot be made more than seven (7) days in advance of such an outage.
6. **"First Future Year - Maintenance and Outage Schedule" -** The First Future Year – Maintenance and Outage Schedule is published on or about March 1 of each year and covers generator outages scheduled for the next calendar year, known as the first future year. This schedule is intended to provide Participants and the System Operator sufficient lead-time to schedule all Planned Outages for the next calendar year. Updates to this schedule are made on a quarterly basis throughout the current year. The December update forms the basis for the January release of the Current Year – Maintenance and Outage Schedule.
7. **"Current Year - Maintenance and Outage Schedule" -** This cycle begins on January 1 of each year and covers the outages scheduled from the current publication date to the end of the current calendar year. Updates are provided on a monthly basis in the Current Year - Maintenance and Outage Schedule.
8. **"Outage Request" -** Outage Request is defined as a request to the System Operator by a Participant for a generator planned or medium notice maintenance outage with more than 15 days notification from the start of the outage. This request may be for outage duration changes, additions, deletions, repositions, or a new request.
9. **"Short Notice Outage Request" -** A Short Notice Outage Request is defined as a request to the System Operator by a Participant for a generator short notice outage with less than 15 days notification, from the start of the outage. This request may be for outage duration changes, additions, deletions, repositioning, or a new request. Economic outages are submitted using a Short Notice Outage Request, but an economic outage cannot be submitted more than seven (7) days in advance of the start of such outage.

Procedures

1. System Operator Responsibilities

1.1. Evaluation Principles

The System Operator shall evaluate, all generator outage requests submitted by Participants for their impact on system reliability. Outages of an interconnection facilities will be included as part of this evaluation.

The purpose of System Operator's evaluation is to identify if generator outages cause either a Transmission Criteria Violation or result in a negative operable capacity margin.

The System Operator will assign each outage request a tracking number upon receipt. Each request will be time and date stamped for prioritization purposes, and evaluated on first come first served basis.

1.2. Outage Request Approval Principles

Participants must receive System Operator's approval to remove a generating unit from service for a planned, maintenance, short notice or economic outage.

The System Operator will approve all generation planned, maintenance, short notice and economic outage.

The System Operator shall prioritize outage requests in the following order:

a. Forced Outages
b. All outages on the Current Year - Maintenance and Outage Schedule.
c. Outage requests approved since the last Current Year - Maintenance and Outage Schedule was distributed.
d. Short notice outages
e. Economic outages and all other maintenance requests will be given the lowest priority and processed on a first come first served basis.

2. First Future Year - Maintenance and Outage Schedule

2.1. First Future Year Outage Request Processing

The System Operator will respond to a Participant's First Future Year Outage Request for an outage duration change, addition, deletion, and repositioning as follows:

a. The System Operator will attempt to locate, within the outage commencement window supplied by the Participant, an acceptable period for the requested outage.
b. The System Operator will notify the Participant if the request is approved as submitted, or approved with modifications.

For First Future Year - Maintenance and Outage Scheduling requests, the System Operator will process generator outage requests as promptly as possible, and at the 1st, in time for the next quarterly publication.

2.2. First Future Year System Operator Reporting

The System Operator will publish the First Future Year - Maintenance and Outage Schedule on or about March 1, June 1, September 1 and December 1.

This process provides the Participants with a planning tool for reviewing their maintenance requirements and timing, and comparing that timing with the needs of the Control Area. This process provides the System Operator with a method for coordinating unit maintenance requirements to minimize the impact of unit unavailability on system reliability, and as a result, the System Operator can identify potential capacity deficient periods.

2.3. First Future Year Resolving Reliability and Security Violations

The System Operator will work with the Participants to reposition scheduled generation planned and maintenance outages the First Future Year - Maintenance and Outage Schedule.

The System Operator shall request that all parties either voluntarily reposition their requested outage or provide the System Operator with alternatives for repositioning their outage. System Operator shall specify the time Participants have to respond to this request.

In making its determination, the System Operator will group the requests by time stamp period, and then apply an allocation method. The method will be based upon each parties total generating capability compared to the sum of the requesting parties total generating capability. Previously approved outage requests will not be subjected to the allocation process.

3. Current Year - Maintenance and Outage Schedule

(To be developed in a similar way as previous one)

4. Short Notice Outage Request

(To be developed in a similar way as previous one)

5. Participant Responsibility

5.1. Information Requirements

Participants must schedule generator planned, maintenance, short notice and economic outages in accordance with this procedure and must provide all information required by this procedure, in the time frames indicated. Participants must submit all generation planned maintenance, medium and short notice and economic outage requests in accordance with this procedure. When submitting a generator outage request for either the current year or first future year, Participants must provide the following information for each request:

a. Name of Unit or Station
b. Amount of reduction in plant generation capacity
c. Preferred outage start date and time
d. Projected outage end date and time
e. Duration of outage (weeks and/or days)
f. Desired season for outage placement
g. Description of work to be accomplished during the outage

5.2. Short Notice Outage Request Information

Submit to the System Operator generation coordinator/forecaster. Initial submissions by telephone with subsequent submittal of written request.

- Typical Outage Start and Ending Times

- Expected To Be Available
- Unit Type
- Beginning Time
- End Time
- Time that unit is expected to return to service

5.3. System Operator Approval

Prior to removing a unit from service, Participants must obtain the System Operator approval for all requests for generation planned maintenance, short notice and economic outages.

6. *Operating procedure No.6:* Power system restoration

Introduction

This procedure addresses restoration of the Mongolia power system (110kV and above and selected 35kV facilities) after a partial or complete system blackout. Expeditious restoration of the power system depends on independent actions and interactions by Participants and the System Operator. Depending on the expanse of the blackout (local area or widespread) numerous Participant restoration procedures, and this procedure, may need to be implemented simultaneously.

Technical aspects of system restoration (i.e. unit startups, load pickups, switching surges, voltages, frequency, synchronization of islands, etc.) will be crucial. Recognizing these concerns, this procedure and Participant restoration procedure have been developed in a coordinated fashion. This document:

- Outlines the responsibilities of the System Operator
- Provides technical guidelines for the restoration of transmission and generation facilities.

System Operator

1. Determine the extent of the blackout throughout the power system and adjacent power systems and inform all Participants of existing generation and transmission capabilities.
2. Implement the System Operator restoration procedure (including necessary coordination with the Participants and adjacent power systems).
3. System Operator assigns a loader to direct the startup and loading of units.

The loader must ensure that:

- The technical guidelines which relate to unit startups, synchronization and loading are followed and,
- Unit operations are closely coordinated with switching operations.

Once the system is sufficiently restored and interconnected, unit dispatch will be resumed by the System Operator.

4. Assign a restoration coordinator to perform the following duties:
   a. Establish communications with restoration coordinators in the participants' territories and adjacent power systems and a flow of information that promotes coordinated system restoration.
   b. Monitors, advises and helps to coordinate with the participants and adjacent power systems, the following:
      - Energizing of high voltage system circuits;
      - Energizing of interconnection ties;
      - Unit startups, load pickups, generation reserves and load shedding within interconnected systems after tie connections has been established.
   c. Maintain a record of the power system blackout and restoration.
   d. Provide updates on the status of the power system to the participants and adjacent power systems.

5. Authorize the closing of interconnection transmission lines.
6. Once tie lines are energized, oversee and coordinate load pickups within the interconnected parties.
7. Select priority for start-up of power resources.
8. Direct load shedding as necessary to enable continued restoration of interconnected participants or the closing of interconnection ties in a safe and reliable way.
9. Monitor power system transmission and generation facilities and, to the extent practical, take actions to promote system reliability.

System Restoration Guidelines

The following lists guidelines regarding the technical aspects of system restoration. Recognizing the numerous scenarios of possible system blackouts (the expanse of the blackout and resources available for restoration), knowledge of these guidelines is important. They represent a general-purpose tool for system restoration.

1. Opening Circuit Breakers and Switches

System Operator and participants restoration procedures contain detailed instructions regarding the opening of circuit breakers and switches. In most cases, in-place substation procedures provide specific switching instructions to be followed in the event of a substation blackout. Some substations have equipment, which automatically switches into a desired post-blackout configuration.

In general, capacitors and customer loads will be opened and disconnected from the high voltage transmission system. Similarly, circuit breakers or switches on the high voltage kV transmission system will be opened. On the transmission lines with voltage higher than 110kV, step-down transformers will be opened on the high side to avoid the simultaneous energizing of a circuit for voltage higher than 110kV along with a step-down transformer. Step-down transformers off the 110kV system will be opened on either the high or low side.

Participants' operators should have station and distribution capacitors opened in locations where customer load can effectively absorb charging from transmission lines. This will help prevent high voltage conditions on the transmission system and excessive under excitation on generators. Along these lines, operators should anticipate the use of any available reactors to help absorb charging and prevent high voltage.

2. Reviewing Load Tap Changer (LTC) Positions

During system collapse, LTCs on autotransformers could move toward/to extreme tap positions. For example, if a gradual voltage collapse occurs (over several minutes), LTCs could move to full boost positions in an attempt to maintain subtransmission or distribution voltage. Upon collapse, the LTCs would remain in these positions and subsequent reenergizing of the autotransformers could result in excessively high voltages on the low side systems that could result in equipment or load damage. Consequently, LTC positions should be checked prior to energizing of autotransformers. If LTC positions are substantially off nominal, taps should be moved to nominal positions before energizing autotransformers.

3. Generator Start Ups and MW Loadings

During system restoration, generator MW loadings will be primarily dictated by minimum MW loading requirements to ensure unit stability and the need to provide station service power to units without black start capability. Operators at generating stations should, in concert with System Operator and participants operators, endeavor to start as many units as possible. More units mean stronger sources in terms of synchronized inertia and control of frequency and voltage.

Stronger sources will also afford more circuit energizing, unit start-ups, spinning reserve, and load pickups (including larger block sizes of load pickups).

Once initial units have been brought on line and synchronized, they should pick up some/all the minimum load requirements for other units just prior to their startup/synchronization. Once these units start and synchronize their minimum load requirements should be transferred to them by adjusting unit loadings in the synchronized subsystem. This method of providing minimum load requirements to units is generally preferable to doing load pickups after a unit has been synchronized.

4. Spinning Reserves

Initially, when few units are on-line, System Operator operators will not have many options regarding spinning reserves. As restoration progresses and more units are phased in, operators should establish and maintain enough spinning reserve to cover loss of the unit generating at the highest MW level. Eventually, spinning reserves should be adequate to cover loss of the largest generating contingency and have additional reserve for continuing unit start-up demands.

5. Load Pickups

A. Load Block Sizes

In general, load pick up proceeds in block sizes that do not exceed 5% of total synchronized generating capability. One exception to this would involve initial phases of restoration where a large unit with slow governor response is synchronized to a small unit with fast governor response. To avoid overloading the smaller unit after load pickup block sizes should be restricted to 5% of the smaller unit's MVA capability until an additional unit(s) is/are synchronized.

B. Frequency Increase Prior to Load Pick up, Automatic Underfrequency Load Shedding

Large frequency excursions are to be expected during system restoration, to avoid them and other subsequent cascading problems, operators should employ the following methods.

During initial stages of system restoration the block sizes of load pickups are most likely to be at/near the general limit of 5% of synchronized generation capability and large frequency excursions are most probable. Operators can compensate for the frequency dips by first increasing frequency to as high as 50.3 hertz prior to load pickup.

As system size grows and the ratio of load block sizes to synchronized generation decreases, smaller increases in frequency prior to load pickup will become appropriate. Finally, as system sizes reach close to full load, load block sizes should become a small percent of synchronized generation and increasing/maintaining frequency after rather than prior to load pickups should be sufficient.

During restoration, operators should observe analog/instantaneous recordings of frequency response to actual load pickups (if available) and tailor their frequency increases and load block sizes to prevent excessive frequency excursions.

C. Cold Load Pickup

During system restoration, operators will be restoring feeder loads that have been de-energized for unusually long periods of time (commonly referred to as "cold load"). The longer the de-energizing period, the greater the loss of typical on/off cycling and other types of diversity in the load. Upon re-energizing of the load, there may be simultaneous full demands of all the various load components. Consequently, operators should anticipate cold load pickups that are 1.5 - 3 times greater than normal feeder loads. Also, the longer the de-energizing period, the longer it will take for the cold load magnitude to decay to a more typical value. After performing several load pickups, operators should get a better feel of cold versus typical feeder loads.

6. Salient Electrical Concerns during System Restoration

Reliable frequency and voltage performance (both transient and steady state) and reliable circuit energizing are major concerns during system restoration, especially during initial stages. The following general guidelines address these concerns.

A. Transmission Line Charging

Anticipate the introduction of shunt MVAR charging from line energizing and ensure that adequate reactive control exists prior to line energizing.

B. Voltage Schedules at Generators

Generating stations should work to maintain voltage schedules below normal levels during system restoration. This will help combat shunt MVAR charging from lightly loaded transmission lines and consequential high voltage and excessive switching surges. Lower voltage schedules will reduce transmission line MVAR charging and promote leading operation of generators and thus the absorption of transmission line MVAR charging. As system load size increases and significant real power MW flows start to occur on transmission circuits, normal voltage schedules at generating stations may become preferable. In any case, decisions on voltage schedules should be based on actual system voltage levels and leading reactive power limits on generators. If a unit is at/near its leading reactive power limit, other options for absorbing reactive power or reducing the amount of reactive power that has to be absorbed should be exercised to restore leading reactive reserve on generators.

C. Circuit Energizing

Perform circuit energizing in a deliberate manner, checking the status of all associated facilities before and after energizing. Synchronism, reactive conditions, and switching surges should be considered. In general, excessive switching surges are not anticipated for energizing on the 110kV.

In the early stages of system restoration, 330kV line or 330/110kV transformer energizing should be done with a source that is electrically close to the energizing, and has a large capability. As restoration progresses and the total capability of synchronized sources builds up the possibility of excessive switching surges decreases substantially.

The simultaneous energizing of a transmission line and a step-down transformer should be avoided. In cases where this is not possible (no breaker between the line and transformer), the energizing of these circuits should be done with a strong nearby source or in later stages of system restoration when sources are strong.

If upon energizing, a circuit immediately trips out due to relay protection, operators should try to have the lightning arrestors at the terminals of the circuit visually inspected for damage before making another attempt to energize the circuit. If inspection is not possible/timely, parties should be aware of and accept an increased risk for equipment damage during subsequent attempts to energize the circuit and other nearby circuits. The transmission equipment of most concern would be autotransformers.

D. Synchronizations

Generating stations are the preferred locations for synchronizing units, islands or systems together. These stations have synchronizing equipment, which is needed for regular unit phasing. Also, station operators are well versed in synchronizing techniques. In the restoration procedures, some synchronizations are planned at transmission (vs. generating) stations. For these cases, the necessary synchronizing equipment, operator knowledge and communication links to predefined generating stations (to match frequency) have been considered.

7. *Operating procedure No.7:* Actions in an emergency

Introduction

This document establishes procedures to be followed in the event of an operating emergency involving **unusually low frequency**, **equipment overload** or **unacceptable voltage levels** in Mongolia power system. The objectives in establishing these emergency procedures are:

1. To minimize the effect on customer service.
2. To restore the balance between customers' load and available generation in the shortest practicable time.
3. To minimize the risk of damage to transmission and generating equipment, to distribution equipment and to customers' equipment.

System Operator Responsibility

The System Operator has the responsibility and authority to direct the actions that may be required for the implementation of this procedure, such as load shedding or opening of circuits, when the emergency situation involves:

1. An overall capacity deficiency within the power system.
2. Mongolia's interconnections with adjacent systems (UESR).
3. Transmission and/or generating facilities within Mongolia.

Procedure

1. Preparation for Implementation

Normally, the potential need for emergency actions prescribed by this procedure should be determined well in advance of the time the actions must be implemented. This procedure may be implemented either before, during, or after action taken under Operating Procedure No.4 - Action during a capacity deficiency depending on the circumstances of the emergency. However, Operating Procedure No.4 will normally precede implementation of this procedure.

When system conditions indicate that implementation of this procedure may be required, the System Operator and the participants will establish and, if appropriate, maintain continuous communication in preparation for a System Operator directive to implement the procedure. Prompt action may provide time to be more selective in the application of this procedure.

If any participant and the System Operator are unable to establish prompt communication, the participant will proceed to implement the procedure independently.

When time and circumstances allow, the System Operator and the participants shall discuss the emergency conditions and reach consensus on the actions to be taken and the timing of those actions.

When operating circumstances do not allow time for consensus decisions, the System Operator and/or the participant will initiate the necessary actions prescribed by this procedure with the understanding that actions resulting in the higher level of reliability will be taken.

2. Procedures for Low Frequency Conditions

In an emergency characterized by a frequency drop, identification of the deficient area or areas is vital to expedite corrective action. The System Operator control room staff shall establish communications with other interconnected areas, as follows, to determine, if possible, the cause of the frequency decline and the action required to restore frequency to 50.00 Hz.

a. When the cause of the declining frequency is outside of Mongolia:

- Confirm existing interchange schedules with adjacent UESR.
- Regulate the Mongolia ties to maintain the frequency-biased interchange schedules.
- Increase the amount of synchronized reserve to be able to adjust the interchange schedule further, if needed.
- Make known to external areas the amount of emergency capacity Mongolia can make available.
- Actions described in Part B below may be implemented when external areas request assistance from the System Operator. Please note that some of these actions will occur automatically regardless of the area causing the frequency decline.

b. When the cause of the declining frequency is due to a deficiency in Mongolia:

- Confirm existing interchange schedules with UESR.
- Request assistance from UESR up to the emergency transfer limit of the interconnection tie lines.
- When the frequency reaches **49.90** Hz order fast-start non-synchronized units into service as required.
- Direct all thermal generations to their high operating limits (HOL) at maximum response rates.
- When the frequency reaches **49.30** Hz underfrequency relays should provide 10% load relief. By the time the frequency reaches 49.00 Hz, confirm that this relief was provided.
- When the frequency reaches **48.80** Hz underfrequency relays should provide an additional 15% load relief. By the time frequency reaches 48.50 Hz, confirm that this relief was provided.
- If the load shedding by automatic underfrequency relays does not stabilize the frequency and it continues to decline below **48.50** Hz order manual load shedding.
- All stations shall take the necessary action, including separating units from the system, to preserve generation and minimize damages and service interruptions.

3. Procedures for a Transmission Emergency

In the process of operation of the transmission system under emergency conditions the emergency actions, including the switching of transmission elements, implementing voltage reductions, and the shedding of firm load, can be taken by the System Operator and the participants to maintain reliability.

The System Operator and the participant operators are responsible to keep appropriate supervisors at the System Operator and the participants facilities. These supervisors should be advised of conditions that might necessitate management review of the need to implement emergency actions on a pre-contingency basis.

4. Procedures for Unacceptable Voltage Conditions

Major generating stations in Mongolia power system should have specified voltage schedules, to be maintained as closely as possible in system operations. They should also be used by operators and planners in off-line studies of the power system. During certain conditions at a generating station or on the power system, sustained deviations from voltage schedules may be required/unavoidable and minimum and maximum voltages have been established that can be sustained at generating stations during these infrequent conditions.

In addition to voltage schedules, minimum and maximum voltage limits at several key generating or transmission stations should be established to promote system reliability during adverse voltage/reactive conditions. These schedules should define criteria and establish guides for action to be taken to insure that desirable levels of voltage are maintained on the transmission system. The participants control centers shall make every effort to correct unacceptable voltage and shall coordinate actions with the System Operator.

When unacceptable voltage conditions occur and corrective actions described above are not effective, the System Operator control room staff and/or the participant operators should take emergency actions, as defined as defined above for transmission emergency to correct the situation.

The System Operator control room staff and participant operators are responsible to keep appropriate supervisors at the System Operator and the Participants advised of conditions that might necessitate management review of the need to implement Emergency Actions on a pre-contingency basis.

5. Restoration of Load

The System Operator will direct the restoration of any load shed under this procedure when system conditions permit.

6. Instructions for Implementation of Manual Load Shedding

The following instructions are to be observed by the System Operator Control Room Staff during the manual shedding of load.

All participants will be on the party line prior to the time the System Operator Control Room Staff issues instructions.

a. Quantity of Load

The System Operator Control Room Staff will direct the quantity of load to be shed or restored by specifying a step number corresponding to the percentage of load to be shed.

$$\text{Step Number} = \frac{\text{Total MW Load to be Shed or Restored} \times 100}{\text{Instantaneous power system Load}}$$

b. Instruction Messages

The System Operator Control Room Staff will issue concise verbal instructions and await participant acknowledgment, which should be received from all participants alphabetically.

8. *Operating procedure No.8:* Operating reserve

Introduction

Operable capability in addition to the quantity required to meet the actual Mongolia Power System load, is required to reliably operate the interconnected electric power system. Such additional capability, provides for:

1. Loss of generating equipment within the power system.
2. Loss of transmission equipment within the power system or between Mongolia and UESR that might result in a reduction of energy transfer capability.
3. Errors in forecasting the power system load.

This procedure sets forth criteria for the establishment and administration of Operating Reserve and AGC in the Mongolia power system.

The objective is to ensure that Mongolia's power resource system is operated at the prescribed level of reliability.

Definitions

Operable Capability - The high operating limit of a resource, such as a generator, contract, dispatchable or interruptible load, etc.

Synchronized Reserve Capability - The unused portion of operable capability which is synchronized to the system and ready to pick up load and the capability that can be made available by curtailing dispatchable loads.

Nonsynchronized Reserve Capability - That portion of operable capability that is available for synchronizing to the system plus the capability made available by the curtailment of interruptible loads. Other load relief management techniques, such as voltage reduction load relief available within ten minutes, may be counted as nonsynchronized reserve after implementation of Operating Procedure No.4 - Action during a Capacity Deficiency.

Operating Reserve - The sum of synchronized and nonsynchronized Reserve.

Automatic Generation Control (AGC) - is a measure of the ability of a generator or portion thereof to respond automatically within a specified time to a remote direction from the System Operator to increase or decrease the level of output in order to control frequency and to maintain currently proper power flows into and out of the Moldtranselectro power system.

Reportable Events:

- Loss of generation or load equal to or greater than 100 MW.
- System frequency deviations equal to or greater than 0.03 Hz.

Operating Reserve Distribution

Operating Reserve shall be distributed to ensure that it can be fully utilized by the System Operator for any probable contingency without exceeding transmission system limitations and to ensure operation in accordance with operating procedures.

Operating Reserve Restrictions

When allocating operating reserve to the various resources, particular attention must be given to temporary limitations and deratings. Only that capability that can actually supply MW in the applicable period shall be classified as operating reserve.

It is recognized that units called upon to activate reserve will operate without relief until the System Operator determines they are no longer needed.

Shortage of Operating Reserve

Operating Reserve will be provided to prescribed levels of synchronized and non-synchronized reserve from within UESR. If available capability is insufficient to provide adequate operating reserve, System Operator will implement the various Actions of Operating Procedure No.4.

Testing Of Thermal Unit Response Rates

System Operator has the responsibility to conduct tests of the response rates. The ability of internal combustion units to start and demonstrate operating reserve capability shall be tested at regular intervals. System Operator will attempt to coordinate these tests with system conditions and participants' normal testing practices.

Responsibility

System Operator is responsible for operating the power system in accordance with established criteria. This includes the responsibility for determining when operating reserve above minimum levels prescribed will be retained.

System Operator is also responsible for determining the required amount of operating reserve; for specifying the type, location, and quantity to be maintained; for communicating the directive to units for activating operating reserve in response to contingencies in the power system.

Participants are responsible for communicating to System Operator current system conditions affecting operating reserve. The participants are also responsible for activating operating reserve for localized problems within a local area when time does not permit communication with System Operator.

9. *Operating procedures No.9:* Scheduling and dispatching of external contracts

Introduction

This procedure describes the actions that the System Operator must perform, with respect to power system scheduling and dispatch, in order to implement external contracts. Information regarding each external contract and its implementation parameters must be submitted to System Operator in accordance with Market Rules and Procedures. Any external contract for which incomplete information is submitted will not be accepted by System Operator for implementation. System Operator will verify all transmission arrangements related to external contracts and the adequacy of contract information submittal.

Any transmission service that is required from a transmission provider internal or external to Mongolia must be obtained by a party(ies) to the transaction, and must be obtained from the transmission provider or from its designated tariff administrator. Such service must be obtained prior to the time that the System Operator is requested to implement any transaction that is dependent on that transmission service.

Transmission Restrictions

Transmission restrictions imposed by an external transmission provider or its Control Area Operating Authority will be accepted and applied by System Operator. The restrictions will be reflected in the schedule and availability data that will be sent to System Operator Settlements for processing according to Market Rules and Procedures.

General Information

The System Operator scheduling office will validate contract submittals in order of submission.

After verifying that appropriate transmission arrangements are in place, the contract information submittal is complete, and that external Control Area involved have a record of the transaction, the System Operator will implement the external contract in accordance with the requested schedule, unless system reliability considerations require an adjustment to the requested schedule or prevent such implementation altogether.

Through Transactions

The System Operator scheduling office will verify that appropriate and adequate transmission arrangements are in place with respect to the use of transmission system prior to implementing a through transaction.

Through transactions do not affect System Operator's power dispatch activities. Such a contract may affect System Operator's power dispatch to the extent that it results in congestion on a transmission interface internal to Mongolia power system.

Check out with Neighboring Dispatch Zones

The System Operator scheduling office will perform the day ahead check out by transaction of energy scheduled with the neighboring dispatch zone to develop the preliminary interchange. The System Operator will perform the real time check out with the neighboring dispatch zone.

Curtailment of External Contracts

The System Operator will be prepared to curtail each and all of the external contracts that have been scheduled across if necessary to maintain system reliability.

Curtailment or interruption may be due to, but not limited to:

a. A limited set of specified pre-determined conditions,
b. Transmission restrictions (both internal and external),
c. Transmission interruption,
d. Other system reliability concerns.

Notifications

When an external contract for sale from an internal seller to an external purchaser must be curtailed, the System Operator will inform the scheduling office. The scheduling office will inform both parties as soon as possible after the System Operator becomes aware of the existence of conditions that prevent or restrict energy deliveries.

When an external seller or its dispatch authority informs the System Operator that Mongolia participant's purchase must be curtailed, the System Operator will notify the scheduling office. The scheduling office will advise the internal purchaser as soon as possible of the actual or pending curtailment and, to the extent of its knowledge, the reason for the curtailment and its expected duration.

Settlement Information

The schedule and availability data will be sent to Settlements Department for processing in accordance with Market Rules.

SECTION VII: ASSESSMENT OF NDC READINESS TO FUNCTION AS A SYSTEM OPERATOR AND PRELIMINARY SCHEDULE AND COST ESTIMATE OF MARKET IMPLEMENTATION

1. Introduction

The purpose of this consultancy is to provide the Economic Reform and Competitiveness (EPRC) Project with an independent determination of the National Dispatch Center's (NDC's) readiness to perform the necessary functions of a System Operator (SO). It is envisioned that Mongolia's current "Single Buyer Market" will be replaced with a bilateral contracts market supported with a balancing mechanism to cover deviations from contract quantities. In the new market, NDC would become the SO with the functions summarized in Part 3. The SO will need adequate hardware, software and training to facilitate communications, control, data acquisition, metering, billing and settlement under the new market structure.

Consistent with the transformation to the new market structure, Draft Market Rules have been developed and reflect comments received in the course of a stakeholder review process. The SO's role in the new market will ultimately be as defined in the final version of the Market Rules approved by ERA.

This assessment follows an earlier evaluation of the National Dispatch Center (NDC) staff's capability to perform the function of the market operator[1]. The earlier study considered the ability of NDC staff to develop dispatch schedules, implement bi-lateral agreements between generation and load serving entities, monitor actual market participant performance, administer the spot market, and perform market settlement, billing, collection and disbursement duties. This study assesses the NDC staff ability to perform the roles and responsibilities defined in the Draft Market Rules following completion of the Supervisory Control and Data Acquisition (SCADA) project that is soon scheduled for completion (see Part 4). The SCADA system will extend considerably NDC's capacity to perform the functions of the SO. Specifically, this assessment includes the following activities:

- A review and evaluation of the ongoing work by the contractors for the SCADA project
- A technical review of the NDC's communication, metering, data acquisition and market settlement capabilities, following completion of the SCADA project, in relationship to what would be required for a modern market operator/dispatch organization.
- A management level assessment of minimum and optimal additional technical requirements and training including a rough cost estimate of additional technical systems and software requirements.
- An estimate of the schedule for implementation of any additional technical and training requirements and the date the NDC could be prepared to operate as the SO with an ability to implement bi-lateral sale/purchase agreements and to settle spot market including any intermediate steps.

This report documents the results of the assessment, and is organized as follows:

- Introduction

[1] See *Evaluation of the NDC's Technical Capacity to Perform the Function of the Independent Market Operator* by Michael Bekker, EPRC Project, January 2006,

- Overview of Mongolian power system
- Description of the proposed electricity market and responsibilities of the SO
- Description and status of NDC projects
- Assessment of NDC readiness to perform SO function
- Additional technical and training requirements
- Cost estimate and implementation schedule

2. Overview of Mongolian Power System

The electric power system in Mongolia consists of three independent electric power systems: the Central Energy System (CES), the Western Energy System (WES), and the Eastern Energy System (EES). The Central Energy System is the primary electric system, representing 80% of all Mongolia electricity supply. The new competitive market structure will be applicable to the CES, so it is the focus of this assessment. Whenever used in this report the word power system will refer to the CES.

The CES power supply is comprised of five coal burning combined heat and power (CHP) generating plants with a total installed electrical nameplate capacity of 753MW[2]. There is a contract with Inter RAO of Russia to supply up to 160 MW of capacity through a double circuit 220kV transmission line that is normally operated at 110kV. The contract is in effect through December 31, 2007. There is also a contract with Inter RAO for power exports that normally consist of excess power arising from heat demand during the off-peak electricity demand hours.

The CES transmission system interconnects three main load centers - Ulaanbaatar, Darkhan and Erdenet and the power plants in these cities by a 220kV transmission line ring. Transmission voltages are 220kV and 110kV. The National Dispatch Center is responsible for coordinating daily system operation of all power and heat sector entities.

The existing capacity of CHP plants is generally sufficient from the point of view of installed capacity requirements of the power system with the annual peak of 571MW set this past winter. However, power plant equipment is for the most part aged, with the youngest plant, Ulaanbaatar CHP 4, commencing operation in 1981. CHP 4 is the only plant capable of ramping up and down in response to dispatch instructions from NDC, but ramping must be done manually (i.e., there is no automatic generation control). When severe disturbances occur on the system, Mongolia leans on the interconnection with Russia for support. The Russian system is much larger than Mongolia's, so can help in a variety of ways during system emergencies as allowed under the contract.

All five of Mongolia's generators can provide voltage regulation and some limited load following and frequency regulation.. In addition, seven reactors are located around the network for voltage regulation. They are switched in and out of service each summer and winter.

3. Description of the proposed Electricity Market responsibilities of the SO

A summary description of the proposed market design as outlined in the current Draft Market Rules[3] follows:

[2] Of the 753 MW nameplate capacity, only 633 MW represent available capacity.
[3] See *Draft Wholesale Power Market Rules* dated February 25, 2006.

- The wholesale power market will be based on a system of bilateral contracts for the purchase and sale of electric power and energy, including contracts between:
  - Distribution Companies and Generating Companies
  - Generating Companies and Exporters
  - Importers and Distribution Companies
- Initially, vesting contracts will be established by the ERA on the basis of costs and assigned between Generators and Distributors. Bilateral vesting contracts will cover the entire generating capacity of the power system and will be settled monthly, and payment will be made directly from buyer to seller. It is envisioned that this "vesting" period will gradually be phased out until each Distributor is allowed to freely negotiate its full supply requirements with any supplier it chooses.
- As actual consumption/delivery amounts can be different from contract quantities (i.e., owing to sudden forced outages of equipment), a balancing (spot) market will be used to settle the differences between actual and contract amounts. All plants under bilateral contracts will be dispatched by the SO on the basis of lowest variable cost while taking into account heating requirements and system constrains. Consumption/supply deviations from contract amounts will be settled at the variable cost of the marginal plant; i.e., the variable cost of the highest cost plant/import dispatched during the period.
- The SO has the right to demand that Generators provide ancillary services pursuant to license obligations. Compensation for the costs incurred by generators to provide ancillary services will be included in the generation tariff and paid through bilateral contracts established by the ERA.
- The SO will dispatch all generators under bilateral contracts on the basis of lowest variable cost while minimizing transmission line losses, maintaining power flows within transmission line limitations, honoring all reliability criteria and respecting generator unit constrains; i.e., minimum load levels, ramp rates, etc.
- In the future, market participants may have the opportunity to arrange bilateral contracts for sales over the interconnection with Russia. However, in the near-term vesting period, all the needs of Distribution Companies will be met with generation from Mongolian power plants and imports from Russia under the current contract. The current contract with Russia will continue to be managed by the Transmission Company and be used principally for various ancillary services.
- Distribution Companies will be subject to a transmission tariff based on the revenue requirement of the transmission company spread across sales. The market rules indicate that there should be an incentive clause included in the tariff establishing a benchmark for transmission losses, with the objective of encouraging the transmission company to manage non-technical losses.

A summary of the responsibilities of the SO as described in the current Draft Market Rules follows.

The main responsibility of the SO is to ensure the safe, reliable and efficient operation of the interconnected electric power system while administering power market operation. In the process of fulfilling its functions with regard to dispatch control, the SO should require that all market participants comply with certain requirements associated with maintaining power system security

and stability in order to assure reliable power supply to consumers. These requirements should be based upon criteria and reliability rules as adopted for the National Power System of Mongolia. Otherwise, the SO's influence on commercial relations among market participants should be confined to the power system regime's planning and real time operation, and to the conduct of technical evaluation of bilateral contracts. Based upon the results of the technical evaluation, the SO can terminate or limit the execution of certain contracts and/or require changes in the amount of capacity specified under the bilateral contract.

Specifically, the SO has five principal responsibilities to carry out consistent with operating and planning criteria, as follows:

1. Plan the system
   a. Near-term – system simulation to minimize supply costs (including transmission losses) based on load forecast (including load shape), outage schedules/unit availability, imports/exports, transmission constraints and ancillary services needs
   b. Medium/long-term – system simulation to develop expansion needs for both generation and transmission from adequacy and cost minimization perspectives; i.e., minimize cost of generation and transmission accounting for transmission losses and the costs to re-dispatch generation owing to transmission constraints
2. Pre-dispatch
   a. System simulation to minimize supply costs (including transmission losses) based on load forecast (including load shape), outage schedules/unit availability, imports/exports, transmission constraints and need for ancillary services; conduct additional system simulations to until a feasible solution is obtained; communicate pre-dispatch schedule to generators
3. Real-time dispatch
   a. When there is a change from preliminary dispatch schedule (i.e., sudden loss of generator), re-simulate the system to minimize supply costs (including transmission losses) based on load forecast (including load shape), outage schedules/unit availability, imports/exports, transmission constraints and need for ancillary services taking into account the changes in system status from the pre-dispatch schedule; communicate re-dispatch schedule in real-time to generators
4. Billing and settlement
   a. Meter production/consumption with commercial-grade accuracy and redundancy
   b. Acquire production/consumption data and compare actual to scheduled production
   c. Apply production/consumption data to determine transmission charges
   d. Produce bills on basis of contracts, balancing, ancillary services, transmission use and SO service charges
   e. Collection and Disbursement
5. Market information
   a. Maintain website with market information
   b. Publish relevant market-related reports

c. Archive market information for at least 5 years; i.e., for billing purposes, for market monitoring, etc.

4. Description and status of NDC projects

NDC currently has two projects underway that will significantly enhance its ability to perform the SO function, as follows:

- Project 1: Establishment of a SCADA System[4] in the CES; and
- Project 2: Establishment of a New Automatic Meter Reading (AMR) System in the CES.

Project 1 includes installation of a new Supervisory Control and Data Acquisition (SCADA) system and training of operating personnel. NDC has chosen to install the Siemens SINAUT Spectrum 4.4 system. The SINAUT system has the capability to cover the entire performance range of electricity system dispatch centers. It is a modular system enabling users to select only those components that are needed for their particular system design. NDC has chosen a system that best meets its system configuration while taking into account budget limitations.

The SINAUT system, once installed, will enable the NDC to monitor in real-time the configuration of 13 sub-stations, including all five generating stations, the interconnection with Russia and seven other key sub-stations on the system. Each of the 13 substations will be linked to the NDC through a new fiber optic cable. The SCADA system will accumulate and store these data for up to two years internally, before downloading to tape where the data can be stored indefinitely.

The information that can be monitored includes energy flows, current, voltage, reactive power, generator output, status of switchgear (i.e., breaker and disconnect switch positions), etc., thus alerting NDC operators to problems in real-time; i.e., energy flows exceeding transmission line thermal limits, breaker trips forcing generating units out of service, etc. The SCADA system enables real-time monitoring and data acquisition and storage, but does not enable remote control of facilities. There is no automatic control equipment on generators or substations, so control will continue to be done through person-to-person communications. Dedicated phone lines between the NDC and the critical sub-stations improve the reliability of the communications network. All telephone conversations between NDC and power companies are recorded both at NDC and the power company. Communications are stored internally for 45 days before being downloaded to more permanent media; i.e., tapes.

Under the current schedule, the SCADA project is to be fully implemented by April 1, 2006. However, at a meeting with NDC project staff on March 14, 2006, the Consultants were informed that the project is delayed owing to problems with the power line carrier (the tuning units require adjustment). As a result, the expected completion date is late June 2006.

Over the next three months, a number of tasks will be undertaken to complete the installation, including:

- On April 1, 2006, testing of the SCADA system will be initiated. This task is scheduled for completion 90 days after initiation, by June 30, 2006.

[4] In the project documentation this project is referred to as *Establishment of a New Load Dispatch System in the CES*.

- Training on use of the SCADA system will include two one-month sessions for three operators.
- There will be ongoing training of operators during the three-month testing procedure.
- Resolution of the power line carrier problem and full installation of the SCADA system will be completed by June 30, 2006.

Project 2 relating to the automatic metering system has not yet been awarded to a contractor. NDC is currently preparing tender documents and expects to award the contact in two months[5]. The project will take seven months to complete following award.

Under the AMR project, a new AMR and telecommunications system will be established to enable measurement and data storage of consumption (Distribution Companies) and delivery (Generators) information regarding each market participant's activity at the wholesale level. The AMR central station will be located at the NDC site (5th floor) and will include all modems and interfaces to the meters at substations and generating stations. The AMR system will utilize a mix of GSM, power line carrier and fiber optic communications equipment (provided under the SCADA project). The technology to be used will be a function of what is available at the site. GSM is to be used only if there is no communication infrastructure at a site. The metering system will include meters, interfaces between the meters and the central station and metering data collection (communications) facilities.

The AMR will include 880 electronic meters enabling measurement and data storage for every delivery and off-take point on the transmission system. Roughly 400 of these meters are already installed on the system. Another 480 meters will be procured under the project, and will be installed by the Transmission Company. Under the project, all meters will be linked to the central station and will measure, as a minimum:

- Active and reactive energy
- Exchanges on interconnection links with Russia
- Losses on the transmission network
- Consumption of auxiliary services within the substations

The meters will have data storage for at least three months, and have a measuring frequency of 15 minutes integrated hourly. The AMR will verify and validate the data. The meters will be of commercial quality without duplication[6].

The project will include an extensive training program structured as follows:

- System administrator — one week for three persons
- Administrator Database — two weeks for three persons
- Modems/IEDs[7]/System Operator — one week for three persons
- Basic User/Advanced User — one week for three persons

Training will occur both during commissioning and following installation for new system users. In addition, on-the-job training will be provided during all project phases.

[5] NDC staff indicated that the two-month estimate represents a minimum.
[6] Back-up will be provided by existing metering installations.
[7] Intelligent electronic device (IED).

In summary, upon completion of this project, the NDC will have a state-of-the-art metering system enabling it to meet the metering requirements of most any market structure.

5. Assessment of NDC Readiness to perform SO function

The initial market design governed by the Draft Market Rules is a system of vesting contracts that will be designed by the ERA with NDC input, and assigned between Generation and Distribution Companies. Plant will be centrally dispatched by the NDC on the basis of lowest variable cost. Differences between bilateral contract amounts and actual delivery/consumption amounts will be priced at the marginal cost of supply. Therefore, the SO must be capable of tracking amounts consumed and delivered at every delivery point on the grid on an hourly basis. The SO must also be able to plan the system, assemble pre-dispatch schedules, dispatch in real-time, do billing and settlement and produce and publish market information.

The NDC can do a number of these things today. For example, the NDC currently conducts planning, develops preliminary dispatch schedules conducts and real-time dispatch. There are dedicated telephone lines with recording capability between the NDC and each generating station to communicate dispatch instructions and enable verification. The NDC currently bills customers monthly, and would be in position to operate as the SO today if monthly settlement were acceptable. However, balancing requires that settlement be done hourly. This requirement means that the AMR and a billing and settlement system that interfaces with the AMR is a pre-requisite for the NDC to perform the SO function in the new market.

Once the SCADA and AMR projects are completed, the NDC's ability to perform the functions of the SO will be much improved. The NDC will have a complete set of data on all of its critical substations in real-time, thus improving its ability to dispatch and maintain system reliability, and a complete set of consumption and delivery data for each market participant, thus enabling it to produce market information reports and conduct the billing and settlement process.

The NDC will have all of the hardware and software necessary to perform the role of the SO envisioned in the Market Rules with the exception of a commercial-grade wholesale billing and settlement system. Billing and settlement consists of processing the AMR data, calculating and producing the bills, issuing the bills and collecting receivables and disbursing payments. Although the market proposed for Mongolia is relatively simple and straightforward, hourly metering and settlement is complex, requiring a fair amount of data manipulation. Mongolia's market will evolve over time as increasing levels of competition are introduced in the future. Therefore, a commercial-grade billing and settlement system that is flexible, and readily adaptable to changes in the market is recommended. A commercial-grade billing and settlement system will provide the SO with a proven software package that can withstand the challenges posed by market participants with regard to their settlement statements. NDC will need comprehensive training on the new billing and settlement system, and will need a dedicated staff to administer the system.

Note that the NDC has filed for Ministry of Finance approval a number of projects related to the functions of the SO. These projects include:

- A training simulator that simulates operation of the power system. Such simulators are used to train new staff, and maintain/upgrade the skills of existing staff. Training simulators often include facilities for building training scenarios and monitoring progress of trainees.

- Additional training on PSS/E software that was provided to NDC by PTI-Siemens. Apparently, NDC staff are not comfortable using this software and feel they would benefit from additional training. PSS/E is a system analysis software package that enables control center staff to analyze, and therefore prepare, for various system scenarios that may arise, thus making them better system operators.
- Addition of an Energy Management System (EMS) to the SCADA system (once in place). An EMS package enables NDC staff to dispatch plant on the basis of least cost. It provides a merit order stack of generating units based on variable cost, thus enabling least cost dispatch and minimization of fuel costs.
- A billing and settlement system for taking data from the AMR system, applying appropriate tariffs, and producing an invoice. In fact, billing and settlement was originally a component of the AMR project, but was cut owing to budget limitations.

The Ministry of Finance review process is such that each of the power sector entities submits a "wish list" of projects for funding. The Ministry evaluates each project, prioritizes the projects and then approves projects in order of priority up to the budget limit. The process has already been completed for 2006, and project submissions will not be made again until the 2007 fiscal year. KfW has indicated an interest in funding power sector projects, particularly those with an energy efficiency component. KfW is in fact funding the SCADA and AMR projects. However, it is the Ministry of Finance that decides which projects will go forward. None of the projects submitted by NDC have a chance of being approved by the Ministry of Finance before 2007.

Although each of the projects submitted to the Ministry will aid the NDC in doing a better job, only the billing and settlement system is required in order for the NDC to carry out the functions of the SO. Economic merit order dispatch is certainly critical to cost minimization on the power system. On the other hand, when there are only five power plants on the system, economic merit order dispatch is not a complicated process. Likewise, a training simulator and system analysis software would certainly improve operator performance, but the NDC is getting by adequately without these aids today, so they are not considered critical to performing the function of the SO in the new market.

A description of the required billing and settlement project is provided below. This description is based on discussions with billing and settlement system vendors.

Billing and Settlement System

A commercial-grade billing and settlement system is necessary for the SO to perform the billing and settlement function under the new market structure. The new billing and settlement system will interface with the AMR system, and calculate and produce invoices on the basis of consumption and delivery data provided by the AMR system, and tariffs/prices provided by the SO. Installation of a commercial-grade billing and settlement system includes two principal components:

- The "product" consisting of various software packages that perform the billing and settlement function; and
- System integration including definition, design and development of the product, and project management activities such as implementation assistance, integration, testing, training and documentation.

Vendors for billing and settlement systems are reluctant to provide cost and schedule information without a formal definition of the system requirements. However, a high-level cost estimate of US$ 1 million and a schedule for product installation and system integration of six months from the time of contract award was provided. The "product" accounts for about 80% of the total cost.

6. Additional technical and training requirements

In addition to the hardware and software requirements for NDC to perform the function of the SO, a number of technical assistance/training programs are needed to prepare NDC, ERA and market participants for implementation of the new market. Even though some of these projects relate to the ERA or market participants rather than the SO, the market rules either assign full responsibility for their completion to the SO, or the SO plays a significant role in their development. Each project is described below.

Complete Market Design

A market design has been prepared and presented to market stakeholders. The proposed market design will be modified as necessary according to decisions made by market stakeholders. It is anticipated that any necessary modifications to the market design will be carried out by EPRC staff working out of the Ulaanbaatar office, so there will be no additional costs beyond those already budgeted.

Complete Market Rules

Market Rules have been drafted and are currently being reviewed by EPRC Project staff. The proposed Market Rules will be modified as necessary according to decisions made by market stakeholders. It is anticipated that any necessary modifications to the Market Rules will be carried out by EPRC staff working out of the Ulaanbaatar office, so there will be no additional costs beyond those already budgeted.

Develop Bilateral Vesting Contracts

Bilateral vesting contracts will govern transactions between generators and distributors. These contracts must reflect the costs of each generator, and be assigned to distributors proportionally while matching the needs of the distributor's customers. The contracts must include a two-part tariff with an energy charge reflecting the generator's variable costs (i.e., fuel and variable operation and maintenance), and a capacity charge reflecting the generator's fixed costs. In addition, the contracts must include the usual contract clauses including financial assurances.

It is understood that bilateral vesting contracts will be developed by EPRC staff working out of the Ulaanbaatar office, so there will be no additional costs beyond those already budgeted.

Develop Transmission Tariff

A transmission tariff will be developed to recover the revenue requirement of the transmission company. The transmission tariff will be developed by EPRC staff working out of the Ulaanbaatar office, so there will be no additional costs beyond those already budgeted. In any case costs associated with the development of transmission tariff would have to be incurred regardless of the new market implementation and therefore costs associated with transmission tariff development should not be included in the estimated costs associated with a power market implementation.

Develop SO Service Tariff

An SO service tariff should be developed in order to enable SO to recover the revenue requirement of the system operator. The SO service tariff will be developed by EPRC staff working out of the Ulaanbaatar office, so there will be no additional costs beyond those already budgeted.

System Operator Training

System Operator needs to be staffed by additional personnel of approximately 10 persons to be able to properly execute billing and settlement functions. The personnel should be proficient in market rules application in order to properly implement the market arrangements on a day-to-day basis and to provide necessary training and technical assistance to market participants as needed. To accomplish that an extensive training will be required.

In addition one of the responsibilities of the SO is to produce and publish various market related reports in order to improve the transparency and fairness of the market. Market data and information are vital to the successful operation of the market. It is estimated that a short-term technical assistance (STTA) of about 40 person-days will be needed to provide training to SO personnel and identify the appropriate reports to be developed by the SO. Training of NDC staff on the development of the reports will be a component of the project.

Market Participant Training

The Market Rules require that the SO provide training to market participants on the new market. Specifically, the market participants will need training on the overall operation of the market, and in particular, on their roles, responsibilities and obligations in the new market. It is estimated that a short-term technical assistance of about 25 person-days will be needed to develop and deliver a market participant training program prior to market commencement.

Market System Testing and "Dry Run" Market Exercises

Prior to market commencement, it is necessary to develop a market system test procedure to ensure that the SO and all market participants are fully prepared and aware of their responsibilities in the new market. The simulated market trial – so called "Dry Run", tests and ensures the interoperability of the systems and procedures of the SO and the market participants to ensure the SO is capable of operating the market and directing the operations of market participants. It identifies any deficiencies and the extent to which they require rectifications to permit commencement of market operation.

It is estimated that a short-term technical assistance of about 20 person-days will be needed to develop a market testing and dry run procedure prior to market commencement.

Develop Financial Assurance Policy

Financial assurance is a system of financial guaranties provided by commercial market participants to provide the System Operator with assurance that it will be able to perform the market settlement with regards to market participants to whom payments are due, notwithstanding of a default of individual market participants on their payment obligations for a reasonable period of time until default is cured or defaulted market participant is terminated.

Although development of such a policy is not a part of the SO responsibilities this task is vital to ensuring the viable and liquid market. The SO or at its request may eventually administer the financial assurance fund. To develop this policy which would provide reasonable assurance of uninterrupted payments while being balanced and fair to market participants ERA would need to

form a special task force of representatives of SO, commercial market participants, financial and legal institutions and possibly foreign financial consultants. At this time it is extremely difficult to estimate the cost of developing such a policy.

7. Cost estimate and implementation schedule

Exhibit VII-1 provides a high-level cost estimate for each of the projects required for implementation of the new electricity market in Mongolia. Costs for short-term technical assistances are based on information provided by accounting staff in the EPRC Project Office in Ulaanbaatar. Costs for the billing and settlement system are based on high-level estimates provided by vendors.

Note that Exhibit VII-1 includes only those projects that are not already assigned to EPRC project staff in the Ulaanbaatar office, so represent cash requirements that are outside the current budget. As can be seen, US$ 176,000 is estimated for technical assistance and training, and US$ 1,000,000 for the commercial-grade billing and settlement system.

Exhibit VII-2 provides a high-level schedule for implementation of the new electricity market in Mongolia. Note that the technical assistance and training projects are not on the critical path. Completion of the hardware/software projects are on the critical path, with the schedule based principally on discussion with NDC staff. The schedule for the billing and settlement system is based on discussions with vendors of billing and settlement systems. It is estimated that market commencement could begin in about 14 months, by June 2007 provided the procurement process for the new billing and settlement system is initiated in the next couple of months.

Exhibit VII-1. High-Level Cost Estimate

Task	Level of Effort (Days)	Cost Estimate (US$)
Define and develop market reports	20	42,000
Market participant training	25	50,000
Develop market testing procedure	20	42,000
Develop billing and settlement system	N/A	1,000,000

Exhibit VII-2. Schedule

Task	MONTH (Beginning April 2006)													
	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May
Technical Assistance/Training														
Complete Market Design														
Complete Market Rules														
Develop Bilateral Vesting Contracts														
Develop Transmission Tariff														
Develop IMO Service Charge														
TA on Market Reports														
Market Participant Training														
Develop Market Test Procedure														
Critical Path														
SCADA Project														
AMR Project Procurement														
AMR Project Implementation														
Billing and Settlement Procurement														
Billing and Settlement Implementation														
Market Testing														
Market Commencement														