Economic Policy Reform and Competitiveness Project

Comments to the Generator's Two-Part Tariff Methodology

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ABBREVIATION AND ACRONYMS

CHP	Combined Heat and Power
ERA	Energy Regulatory Authority
EPRC	Economic Policy Reform and Competitiveness Project
NDC	National Dispatcher Center
O&M	Operation and Maintenance
USAID	United States Agency for International Development

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SECTION I: ERA PROPOSED TWO-PART TARIFF – EPRC PROJECT TEAM COMMENTS

The EPRC Project Team has reviewed the ERA proposed two-part tariff documented in the March 20, 2006 Draft *Interim Tariff Methodology for Calculating Electricity Energy and Capacity Tariffs of Generating Licensees*. The purpose of this memorandum is to convey our comments, and submit a sample two-part tariff for the ERA's consideration.

It is understood that this two-part tariff could potentially be adopted for use in the single-buyer market currently in place in Mongolia. As a result, the proposed ERA tariff design is reviewed within the context of this current market structure, in effect, a vertically-integrated market with separate business units. The goal is to promote improved performance of the generating licensees consistent with the ultimate move to greater competition. By implementing this tariff structure now in advance of the bilateral contracts market, generating licensees will be in a better position to "compete" once the new market is introduced.

The concepts discussed in this paper are consistent with the March 31, 2006 Draft *Rules for the Wholesale Power Market of Mongolia National Power System*. However, although the concepts are the same, it should not be assumed that the two-part tariff presented in the attachment could be directly inserted into initial vesting contracts relevant to the bilateral contracts market. The two market designs are much different. For example, in the bilateral contracts market, each distributor will be required to contract for reserve capacity in excess of its peak demand. There is no such requirement under the current market structure. The tariffs in vesting contracts should be developed in conjunction with allocations assigned between generating licensees and distributors because tariffs and allocations are directly related.

Note that whatever design is chosen for the two-part tariff, it must be consistent with the spot market design. Both the two-part tariff and the spot market are designed to encourage improved performance on the part of generating licensees. However, care must be taken to ensure that bonuses and penalties do not overlap. For example, if a generating licensee falls short of production commitments in its agreements, it should be penalized once, in either the two-part tariff or the spot market, and the penalty should be consistent with resulting costs for replacement production. As the spot market covers less than 10% of transactions in the market, it should be modified as necessary to complement the two-part tariff rather than vice-versa.

1. Overview

A well-designed two-part tariff provides incentive to generating licensees to improve operating performance and production efficiency, and results in a fairer allocation of risk between buyer and seller. It rewards generating licensees who are able to improve performance through increased revenues; conversely, it punishes generating licensees whose performance deteriorates through reduced revenues.

A two-part tariff recognizes that a generator provides two services: energy and availability, that is, the ability to deliver energy when called upon.[1] Energy relates to the provision of a useful commodity (i.e., electrical energy), while availability relates to the provision of reliable service.

[1] A generating licensee can also provide various ancillary services. However, under the current regime in Mongolia, a generating licensee is expected to provide ancillary services within the framework of the current pricing format.

The two-part tariff therefore has two components: 1) an energy charge for recovery of the licensee's energy production costs, and 2) a capacity charge for recovery of the licensee's fixed costs; i.e., all costs that are not recovered in the energy charge. A licensee's energy production costs include all variable costs, that is costs that vary with changes in energy production, specifically, primary fuel costs (coal in Mongolia's case) and the component of operation and maintenance costs that vary with production.

Improved efficiency and performance is encouraged through the use of benchmarks as opposed to simply passing all costs through directly to the buyer. Benchmarks are established on the basis of historical performance (perhaps averaged over the past three years), and performance of similar generating units, both internal and external to Mongolia, as necessary. In this way, generating licensees can increase profits if they exceed the benchmarks. Conversely, if they fall short of the benchmarks, the generating licensee will absorb the revenue loss rather than consumers. This is consistent with a competitive market where the best performers generally have higher profit margins.

The benchmarks should be established for a period long enough to allow recovery of investment used to improve performance, for example, three years. Otherwise, the licensees will have no incentive to invest. At the end of the three year period, the benchmarks are re-set to reflect improvements, thus passing along the benefits to consumers.

2. Cost Recovery

The two-part tariff is designed to recover the total revenue requirement of the generating licensee provided the licensee meets target performance benchmarks. The tariff design includes two components – an energy component designed to recover variable costs, and a capacity, or availability, component designed to recover fixed costs. Each component is discussed in greater detail below. To assist in the determination and verification of the revenue requirement, and the cost split between fixed and variable, we have attached a cost template that we recommend be distributed to company accounting units for completion.

In the ERA's proposed two-part tariff, the energy tariff recovers fuel costs only. The energy tariff should be designed to recover all costs that vary with energy production. This normally includes the delivered cost of primary fuel (i.e., coal), and the variable component of operation and maintenance costs; i.e., water, chemicals, labor, maintenance, etc. The cost of fuel is relatively straightforward, but the variable costs of operation and maintenance (O&M) are often not tracked separately in the system of accounts. As a result, it may be necessary to gain the input of station operation and maintenance personnel to define the variable component of O&M costs. When information on variable operation and maintenance costs is not readily available, they may be approximated using percentages of other costs, and in some instances, are based purely on engineering experience and judgment. For example, in the World Bank Report entitled *Design of Electricity Prices for Generation, Transmission and Distribution for Mongolia*, the consultants estimate variable operation and maintenance costs for each of Mongolia's combined heat and power (CHP) plants at US$ 2.00/MWh, or roughly 2400 togrog/MWh (see Table 3.9, page 23). The consultants use the same estimate of variable operation and maintenance costs for a typical coal plant (Table 4.1, page 30). The US$ 2/MWh estimate is consistent with variable O&M cost estimates for various coal technologies quoted in American utility integrated resource plans which generally range from US$ 1 - 2/MWh.

The system of accounts for the Mongolian power sector does not currently track all variable cost components. While there are separate accounts for fuel, variable water, chemicals and lubricants, there are no separate accounts for variable labor and maintenance. In the absence of this detailed information, using the World Bank estimate of 2400 togrog/MWh may serve as a reasonable approximation until the required detailed data become available. This would add 2.4 togrog/kWh to the energy tariffs calculated by the ERA based on fuel costs only, which range from 11.11 to 19.41 togrog/kWh.

Note that the 2.4 togrog/kWh approximation will not affect economic merit order. Neither will it affect a licensee's revenue recovery, and it will have only a minor impact on the efficiency of the price signal in the tariff. It is understood that this estimate falls well within the accuracy of the costs used in the revenue requirement calculation, particularly when one considers that tariffs do not collect the full revenue requirement at this time anyway.

All other costs of the generating licensee related to electricity that are not recovered in the energy charge (i.e., all fixed costs) should be recovered in the capacity charge. Therefore, if 2.4 togrog/kWh is added to the energy cost component, there would be a need to back these costs out of the capacity cost component.

3. Energy Tariff Design

In the ERA's proposed tariff design, the energy tariff collects all costs of fuel regardless of performance. If the licensee's heat rate is deteriorating (i.e., because it does not undertake regular maintenance), the additional cost of fuel is simply passed through to the buyer, thus providing little incentive to the generating licensee to maintain, or improve, production efficiency.

In order to encourage generating licensees to maintain and improve production efficiency, the energy tariff design should be based on the average delivered price of fuel to the generation station in togrog/kcal multiplied by the benchmark heat rate in kcal/kWh. The variable operation and maintenance cost should be added to complete the tariff.

Under a properly designed energy tariff, a generating licensee will recover its variable production costs regardless of the amount of energy produced; i.e., it will be indifferent to dispatch. However, if a licensee is able to improve production efficiency, or make performance improvements that result in reduced variable O&M costs, it will recover more than its variable costs, thus improving profit margins. Conversely, if the licensee's production efficiency or operating performance deteriorates, it will fail to recover its variable costs, and its profit margins will be reduced. Of course in the current market structure, all energy delivered to the wholesale market by a generating licensee that is in excess or is deficient from levels defined in agreements will be priced at levels prevailing in the spot market.

4. Capacity Tariff Design

The ERA's two-part tariff proposal bases the capacity tariff on projected availability of each generating station. It is understood that the availability forecast is based on expected dispatch rather than expected availability. For example, the projected availability for PP4 is only 267 MW. This compares to PP4's installed capacity of 540 MW, and its "net effective capacity" of 441.4 MW (see Table 3.8 of World Bank Report). The capacity tariff should be based on the amount of capacity that the licensee has available for dispatch, whether or not the generator is actually dispatched at this level. The figure should reflect the amount of capacity that the licensee could provide if called upon by the dispatch center. This figure is then adjusted to account for plant outages in the tariff calculation.

A number of capacity tariff design considerations are discussed below.

Maximum Daily Availability: The daily availability should be based on the maximum capacity in MW that the generating licensee can provide on a daily basis. The maximum daily availability should be based on actual experience, or test levels when experience is limited. NDC staff indicate that each generating licensee has a published maximum installed capacity, but this figure is adjusted to account for coal quality considerations and the requirement that a generator/boiler set be in cold reserve. Some of the generating stations were designed for bituminous coal, and are unable to operate at maximum installed capacity levels on lower quality lignite. NDC staff indicate that procedures related to safety and reliability require that each generating station maintain a generator/boiler set in cold reserve. The equipment can be brought out of cold reserve in three or four hours, so serves as replacement capacity for short-term reserves provided over the interconnection with Russia during system emergencies. The resulting capacity de-ratings are accounted for in the net effective capacity values shown in Table 3.8 of the World Bank Report, and it is recommended that the capacity tariff be based on these levels, verified through actual experience or tests, as necessary.

Average Daily Available Capacity: Once the maximum daily available capacity is determined, it is adjusted to account for plant outages in the tariff calculation. There are two types of outages that must be accounted for: planned outages which are outages planned and approved by the NDC in advance, and forced outages which are sudden unforeseen outages that have not been approved in advance by the NDC. Each outage type can be translated to an index that reflects the average amount of the generator output in percent that is expected to be unavailable over the year. The effective forced outage rate takes into account both full and partial plant outages and capacity reductions. Details of the definition and means for calculating the outage indices are provided in Attachment 2 of the *Rules for the Wholesale Power Market of Mongolia National Power System*.

It is understood that generation outage information is not currently tracked in this format in Mongolia. The NDC compiles statistics relating to each planned and forced outage, so the information is available to compute the outage indices. If it is determined that the benchmark effective forced outage rate for a licensee is 5%, and the benchmark planned outage rate is 30 days per year (about 8%), the availability payment would be based on an outage rate of 12.8% (.05*335 days + 1.0 * 30 days = 46.75 days of outages annually divided by 365 days per year). Therefore the maximum daily available capacity would be de-rated by 12.8% in the tariff calculation. PP4 with an effective maximum daily available capacity of 441.4 MW would have an average daily available capacity of 441.4 MW * 0.872 = 384.9 MW.

This represents one methodology for calculating average daily available capacity for the availability payment. As Mongolia's power plants are quite old, it may be desirable to set the planned outage rate annually on the basis of the generating licensee's forecast number of days required for planned maintenance. The average daily available capacity would be calculated as above, using the same effective forced outage rate, and adding the licensee's forecast number of days for planned outage. The drawback with this approach is that generating licensees may exaggerate the number of days required for planned maintenance. This could cost consumers a significant amount of money if a plant such as PP4 stays out of service longer than necessary, requiring replacement of its low-cost energy with higher-cost energy from other power plants.

Seasonal Consideration: Power systems are planned to provide adequate reliability during all hours of the year, but the system is most likely to experience a reliability breach when generation reserves are at their lowest levels. This most often corresponds to periods of system peak demand. It is understood that Mongolia does not undertake reliability studies to determine periods of highest stress on the system. However, winter peak demand in Mongolia is roughly 60% greater than summer peak demand. Clearly, winter peak demand is driving planning decisions relating to commitment and installation of new generating capacity.

Maximum demands in the months of January, February, March, October, November and December are all within 90% of the annual system peak demand (based on monthly and daily load curves shown on page 63 of the July 15, 2002 Master Plan). Without benefit of reliability modeling, a "peak period" cannot be easily defined, but it would appear that the peak period might be defined as these winter months, with the months of April through September defining the off-peak period.

Because the winter period is the time during which the system is under greatest stress, it is more critical that all generation be available. For this reason, two-part tariffs are often designed to recover a greater share of the generator's fixed costs in the peak period. For example, depending of the system load shape and reserve margin, the capacity tariff might be designed to recover 55% of fixed costs in the six peak months, and 45% in the six off-peak months.

We raise this design issue for the consideration of the ERA. The decision on whether to offer higher payments in the peak months should be discussed among Mongolia's power system planning and operating experts. If a decision is made to weight payments more heavily in the winter, agreement would then need to be reached on the definition of the peak months, and the weight to be given to the peak months.

If it is decided to incorporate a seasonal component in the capacity tariff, the average daily availability in the peak months should incorporate the effective forced outage rate only. In the off-peak months, average daily availability should incorporate both the effective forced outage rate and the planned outage rate to reflect the fact that planned maintenance would be undertaken only during the off-peak months.

Bonus Payment: The final capacity tariff design consideration discussed in this paper relates to payment of bonuses[2] for availability beyond target availability used in the capacity tariff calculation. This design consideration is closely related to the previous seasonality design consideration. If the power system has high reserve margins, payments beyond the licensee's fixed costs should be small, and perhaps zero because the value of the additional availability is minimal. Conversely, if reserve margins are below target levels, the value of additional availability is high, so the tariff should be designed to promote high levels of availability by providing generating licensees the opportunity to recover more than their fixed costs. This is consistent with competitive markets where the value of capacity increases substantially when reserve margins are low.

As discussed in the previous section, capacity, or availability, has high value during peak months when generation reserve margins are lower. Therefore, if Mongolia's power system planners and

[2] There is no need to discuss penalties because if a generating licensee fails to meet the availability targets incorporated in the tariff, it will not recover all of its fixed costs. In effect, the poorer the licensee's performance, the lower its revenues.

operators determine that a seasonality component is desirable, the capacity tariff might be designed to allow generating licensees to keep all revenues acquired through the capacity payments in the peak months even if payments exceed the fixed cost recovery assigned to this period (55% of total annual fixed costs using the above example). As capacity has less value in the off-peak months, capacity payments in this period might be limited to the amount of fixed costs assigned to the off-peak period (45% of total annual fixed costs using the above example). Once a licensee receives payments during the off-peak period that amount to 45% of the fixed costs allocated to capacity, no further capacity payments would be made until the next peak month.

5. Summary

There are a number of design considerations that could improve upon the ERA's proposed two-part tariff. However, it is first necessary for the ERA to meet with various power sector planning and operating experts to determine if there is value in promoting greater availability in the peak demand months. Although the power system can currently meet electrical demand requirements, this may soon not be the case if high levels of demand growth are experienced, or if it becomes necessary to retire aged generating plant.

In an effort to assist the ERA with its understanding of the design considerations documented in this paper, we have attached a re-write of ERA's proposed two-part tariff that incorporates the design features discussed in this paper. It also includes a sample two-part tariff calculation. Note that we are not necessarily recommending the attached tariff design. We are simply presenting it as a model in the event the ERA decides to incorporate the design considerations discussed above. If the ERA decides to pursue this design, it will be necessary to:

- Define the peak months;
- Define the relative value of capacity; i.e., how much revenue should be collected in the peak months versus the off-peak months, and the appropriate bonus for exceeding availability targets in the peak months;
- Compile information necessary to define effective forced outage rates and planned outage rates for each generating licensee;
- Define daily average availability targets;
- Define target heat rates; and
- Determine if a US$ 2/MWh estimate of variable O&M costs is acceptable.

Once agreement is reached on the appropriate two-part tariff design, the spot market design should be re-visited to determine if modifications are necessary.

The EPRC Project team is available to assist with such studies if desirable.

SECTION II: INTERM TARIFF METHODOLOGY FOR CALCULATING ELECTRICITY ENERGY AND CAPACITY TARIFFS OF GENERATING LICENSEES

1. Purpose

The purpose of this methodology is to introduce elements in the generation sector that are consistent with competition in the wholesale market, and that create incentives to generators for improved performance in both availability and production efficiency, thus leading to reductions in the overall cost of power.

2. Definitions

1. “Capacity tariff” means a tariff paid for each MW of available capacity of a generating licensee expressed in togrog/MW-day;
2. “Energy tariff” means a tariff paid for each kWh of electrical energy delivered to the wholesale market by a generating licensee in accordance with the agreements and expressed in togrog/kWh;
3. “Daily available capacity” means the daily capacity in MW made available by a generating licensee;
4. “Amount of energy” means an amount of electrical energy in kWh supplied to the wholesale market by a generating licensee in compliance with agreements;
5. “Fixed costs” means the costs recovered by a capacity tariff including a generating licensee’s total fixed cost of electricity generation (expressed in togrog);
6. “Heat rate” is the average conversion efficiency of a generating licensee’s plant applicable during the tariff period, expressed in kcal/kWh;
7. “Cost of coal” is the average cost of coal delivered to a generating licensee’s facility during the tariff period, expressed in togrog/kcal;
8. “Tariff period” is the period during which the tariff will be in effect;
9. “Effective forced outage rate” is the average amount of a generating licensee’s capacity that is unavailable owing to full or partial forced outages (i.e., outages that are not planned and approved in advance by the dispatch licensee), expressed in percent (%);
10. “Planned outage rate” is the average amount of a generating licensee’s capacity that is unavailable owing to planned outages (i.e., outages that are planned and approved in advance by the dispatch licensee), expressed in number of days or percent (%);
11. “Peak months” are the months of January, February, March, October, November and December;
12. “Peak period” is the peak months;
13. “Off-peak months” are the months of April through September, inclusive; and
14. “Off-peak period” is the off-peak months.

3. Calculating the Capacity Tariff

1. The ERA, in conjunction with the dispatch licensee, will determine the “target” availability for each generating licensee for the upcoming tariff period. The target availability will take into

account the current planning regime, and be based on historical performance (i.e., the past three years), and comparison with availability performance with like generators internal to Mongolia, and external to Mongolia, as necessary.

2. The availability target will take into consideration both forced and planned outages. Availability targets will be established for the peak period and the off-peak period. Availability targets for peak months will be established on the basis of the effective forced outage rate of each generating licensee. Availability targets for off-peak months will be established on the basis of the effective forced outage rate and planned outage rate of each generating licensee. Planned outages will be scheduled during the off-peak months, to the extent possible.

3. The ERA will propose availability targets for peak and off-peak periods for each generating licensee, and provide each generating licensee with an opportunity to respond in writing if it believes its availability target requires further consideration. The response prepared by the generating licensee will clearly document why the availability target should be adjusted. The ERA will consider all responses filed by generating licensees, and establish firm availability targets for each generating licensee prior to the tariff period. The ERA's published availability targets will be final and binding on each generating licensee.

4. A generating licensee will report its available capacity to the dispatch licensee on a daily basis, and the dispatch licensee will calculate payments for capacity on the basis of the reported availability and the capacity tariff approved by the ERA.

5. The capacity tariff for a generating licensee will ensure full recovery of a generating licensee's total fixed cost of electricity generation if it meets its target availability in the tariff period.

6. The cost used for calculating a capacity tariff will include all fixed costs of electricity generation. As variable operation and maintenance costs are not tracked separately, it will be necessary to back these costs out of the total of the cost categories shown below:

   6.1 Operating expenses, including depreciation, operations and other;
   6.2 Non-operating expenses, including financing expense, currency exchange gain/loss, taxes other than income and other; and
   6.3 Return on investment including return on equity and return on working capital.

7. The ERA will scrutinize the fixed costs of generating licensees and approve capacity tariffs for the tariff period.

8. For each generating licensee, the capacity tariff is equal to its annual fixed costs divided by the daily available capacity and the total number of days in the period. In order to encourage higher availability in the peak months, 55% of the annual fixed costs will be recovered in the peak period, and 45 % of the annual fixed costs will be recovered in the off-peak period. The capacity tariff will be determined as follows:

For the peak period (January, February, March, October, November and December)

$$\boxed{T_i^{capacity} = \frac{FCi \ * 0.55}{C_i^{average} \ * Days_i^{period}}}$$

For the off-peak period (April through September, inclusive)

$$T_i^{capacity} = \frac{FCi * 0.45}{C_i^{average} * Days_i^{period}}$$

where:

$T_i^{capacity}$ is the capacity tariff for the peak or off-peak period for a particular generating licensee in togrog/MW-day,

FC_i is the total annual fixed cost of electricity for a particular generating licensee (55% is recovered in the peak period and 45% is recovered in the off-peak period) in togrog,

$C_i^{average}$ is the target available capacity for a particular generating licensee during the peak or off-peak periods in MW, and

$Days_i^{period}$ is a number of days in the peak or off-peak period.

9. The dispatch licensee will calculate on a daily basis the capacity payment for each generating licensee based on its approved capacity tariff for the peak or off-peak month and its actual available capacity on the given day, and consolidate at the end of each month.
10. A generating licensee will receive revenue exceeding the fixed costs assigned to the peak period if its actual availability exceeds the target availability established for the peak period. In the off-peak period, a generating licensee will receive no additional capacity payment for availability once it has recovered all fixed costs assigned to the off-peak period. The dispatch licensee will monitor availability and capacity payments made to each generating licensee in the off-peak period, and ensure capacity payments do not exceed the cost recovery assigned to the off-peak period; i.e., revenues during the off-peak period will not exceed 45% of annual fixed costs. In this event, generating licensees will be expected to continue operating even when not receiving capacity payments unless forced out of service, or they receive prior approval for planned maintenance from the dispatch licensee.
11. The dispatch licensee is responsible for ensuring generating licensees can meet their reported available capacity, including the conduct of unannounced availability verification tests when deemed necessary. If a generating licensee is found to be in non-compliance, the generating licensee will be penalized 50% of the capacity payments it has received since the last confirmation of its ability to meet its reported available capacity.

4. Calculating the Energy Tariff

1. The energy tariff will compensate a generating licensee for the variable costs it incurs generating electrical energy up to the amounts specified in its agreements.
2. The ERA, in conjunction with the dispatch licensee, will determine the “target” heat rate for each generating licensee for the tariff period. The target heat rate will be based on historical performance (i.e., the past three years), and comparison with heat rates of like generators internal to Mongolia, and external to Mongolia, as necessary.

3. The ERA will propose target heat rates for each generating licensee, and provide each generating licensee with an opportunity to respond in writing if it believes the target heat rate requires further consideration. The generating licensee's response will clearly document why the target heat rate should be adjusted. The ERA will consider all responses filed by generating licensees, and establish firm target heat rates for each generating licensee prior to the tariff period. The ERA's published target heat rates will be final and binding on each generating licensee.
4. The ERA will scrutinize variable operation and maintenance costs and the cost and heat content specified in coal contracts of each generating licensee for the tariff period.
5. The energy tariff for a generating licensee will equal its average cost of coal purchased during the tariff period multiplied by its target heat rate, plus its variable operation and maintenance cost, as follows:

$$T_i^{energy} = CC_i * HR_i + VOM_i$$

Where:

T_i^{energy} is the energy tariff for a particular generating licensee in togrog/kWh delivered to the grid,

CC_i is the average cost of coal during the tariff period for a particular generating licensee in togrog/kcal,

HR_i is the target heat rate for a particular generating licensee in kcal/kWh, and

VOM_i is the variable operation and maintenance cost for a particular generating licensee in togrog/kWh

5. Spot Market Price

1. A generating licensee will buy an amount of shorted energy or sell excessively generated energy compared with energy amounts included in its agreements in accordance with agreements relating to the Spot Market at the spot market price.

Sample Calculation

Consider the following generator (Values, when available, similar to those of PP4):

- Available capacity = 441.4 MW
- Target forced outage rate = 5%
- Target planned outage = 30 days
- Target heat rate = 4.0 kcal/kWh
- Variable operation and maintenance costs = 2.4 togrog/kWh
- Total annual fixed costs in tariff year = 24,068 million togrog
  (Total fixed costs of 28,742 million togrog less variable O&M of 2.4 togrog/kWh * 1947.5 million kWh)
- Average cost of coal in tariff year = 2.75 togrog/kcal
- 182 days in winter period and 183 days in non-winter period
- 55% of fixed costs recovered in winter period, 45% in non-winter period

Capacity Tariff

For Peak Period (January, February, March, October, November, December)

Outage Factor = Target Forced Outage Rate = 5%

(24,068,000,000 togrog * 0.55) / [441.4 MW * (1 - .05) * 182 days]

= 173,450 togrog/MW-day

For Off-peak Period (April through September, inclusive)

Outage Factor = ((5%*153 days) + 30 days) / 183 days = 0.206

(24,068,000,000 togrog * 0.45) / [441.4 MW * (1 - .206) * 183 days]

= 168,868 togrog/MW-day

In this example, the generating licensee will on most days report an available capacity of 441.4 MW (unless on outage). This availability will be based on actual experience, or tests, when necessary. If the generating licensee meets the target availability in the peak period (95% of 441.4 MW) and the off-peak period (79.4% of 441.4 MW), it will recover all of its 24,068 million togrog fixed costs. If its availability falls short of the target availability, it will not recover all of its fixed costs. If it exceeds the 95% target availability in the peak period, and meets its target availability of 83% in the off-peak period, it will recover more than its fixed costs. The generator will not be allowed to recover more than the fixed costs assigned to the off-peak period, in this case 45% of 24,068 million togrog.

Note that the difference in capacity payments between the peak and off-peak periods is quite large, exceeding 2400 million togrogs. However, the difference in the capacity tariff between the peak and off-peak periods is small (less than 5%). If Mongolia’s power system planning and operating experts believe a stronger price signal is warranted, a greater percentage of the fixed costs (i.e., more than 55%) could be assigned to the peak period.

Energy Tariff

(2.75 togrog/kcal * 4.0 kcal/kWh) + 2.4 togrog/kWh = 13.4 togrog/kWh

The generating licensee will receive 13.4 togrog for each kWh delivered to the grid (i.e., after accounting for station service) up to the amount of energy specified in agreements. Energy above or below those amounts will be credited or debited at the spot market price.

ANNEX: REVENUE REQUIREMENT

Company Name: ___________________________________

Report for year ending: ______________________________

Table G1

Generating Licensees Revenue Requirement

Cost Categories	Current Reporting Year			Prior Reporting Year			Two Years Prior		
	Total	Electricity	Heat	Total	Electricity	Heat	Total	Electricity	Heat
Operations Expenses									
Energy & Related									
Depreciation									
Operations & maintenance									
Administrative									
Other									
Total Operations									
Non-Operations Expenses									
Financing Expense									
Currency Exchange Gain/Loss (1)									
Taxes Other Than Income									
Other									
Total Non-Operations Expenses									
Return on Investment									
Return on Equity									
Return on Working Capital									
Total Return on Investment									
Total Revenue Requirements									

(1) Average for past three years

Executive Director: ________________________________ Date: ____________________

Chief Accountant: _________________________________ Date: ____________________

Company Name: ________________________________

Report for year ending: ___________________________

Table G2

Generating Licensees Operations Expenses

Cost Categories	Current Reporting Year				
	Q1	Q2	Q3	Q4	Total
Operations					
Maintenance					
Administrative					
Sales					
Billing and Collection					
Total					

Cost Categories	Prior Reporting Year				
	Q1	Q2	Q3	Q4	Total
Operations					
Maintenance					
Administrative					
Sales					
Billing and Collection					
Total					

Cost Categories	Two Years Prior				
	Q1	Q2	Q3	Q4	Total
Operations					
Maintenance					
Administrative					
Sales					
Billing and Collection					
Total					

Executive Director: ___________________________ Date: ______________

Chief Accountant: ____________________________ Date: ______________

Company Name: ______________________________

Report for year ending: ______________________

Table G3

Generating Licensees Non-Operations Expenses

Cost Categories	**Current Reporting Year**				
	Q1	**Q2**	**Q3**	**Q4**	**Total**
Financing Expense					
Currency Exchange Gain/Loss					
Other					
Total					

Cost Categories	**Prior Reporting Year**				
	Q1	**Q2**	**Q3**	**Q4**	**Total**
Financing Expense					
Currency Exchange Gain/Loss					
Other					
Total					

Cost Categories	**Two Years Prior**				
	Q1	**Q2**	**Q3**	**Q4**	**Total**
Financing Expense					
Currency Exchange Gain/Loss					
Other					
Total					

Executive Director: _______________________ Date: ____________

Chief Accountant: ________________________ Date: ____________

Company Name: ___________________________________

Report for year ending: ______________________________

Table G4

Outstanding Debt

Line #	Loan Description	Date of Loan	Original Principal Amount		Interest Rate	Outstanding Principal Amount		Annual Interest
			Original Denomination	MNT		Original Denomination	Revalued MNT	
1								
2								
3								
4								
5								
6								
7								
8								
9								
10								
11	**Totals**							
12	**Exchange rate at year-end**							

Executive Director: ___________________________ Date: ______________

Chief Accountant: ____________________________ Date: ______________

Company Name: ________________________________

Report for year ending: ___________________________

Table G5

Generation Non-current Asset Allocation

Account Number	Asset categories	Book Value	Accumulated Depreciation	Annual Depreciation	Allocation %		Electricity			Heat		
					Elec.	Heat	Book Value	Acc. Depr.	Annual Dep.	Book Value	Acc. Depr.	Annual Dep.
20200	Buildings, Structures and Improvements				Fuel Allocation %							
20210	Boiler Plant Equipment				Fuel Allocation %							
20220	Engines and Engine-driven Generators				100%							
20230	Turbines and Generators				100%							
20240	Accessory Electrical Equipment				Determine usage							
20250	Other Power Plant Equipment				Determine usage							
20260	Reservoirs, Dams and Waterways				100%							
20270	Roads, Trails and Bridges				Fuel Allocation %							
20280	Fuel Holders, Producers and Accessories				Fuel Allocation %							
20290	Diesel Generators				100%							
20300	Substation Equipment				100%							
20310	Poles, towers and Fixtures				100%							
20320	Overhead Conductors and Devices				100%							
20330	Underground Conduit and Piping					100%						
20340	Underground Conductors and Devices				100%							
20350	Line Transformers				100%							
20370	Metering Devices				Heat or electricity							
20520	Office Furniture and Equipment				Heat or electricity							
20530	Transportation Equipment				Heat or electricity							
20540	Warehouse Equipment				Heat or electricity							
20550	Tools, Shop and Garage Equipment				Heat or electricity							

20560	Laboratory Equipment				Heat or electricity						
20570	Power Operated Equipment				Heat or electricity						
20580	Communication Equipment				Heat or electricity						
20590	Other Property, Plant and Equipment				Heat or electricity						
20600	Capitalized Spare Parts				Heat or electricity						
21200	Patents				Heat or electricity						
21300	Trademarks and Copyrights				Heat or electricity						
21400	Licenses				Heat or electricity						
21500	Computer Software				Heat or electricity						

Executive Director: ___________________________ Date: ______________

Chief Accountant: ____________________________ Date: ______________

Company Name: ________________________________

Report for year ending: ___________________________

Table G6

Generating Licensees Returns on Investment

Return on Equity			
	Current Year	**%**	**Return on Equity**
Equity			
Working Capital			
	Current Year	**Index**	**Working Capital**
Total Operations Expense			
(-) Depreciation			
(-) Fuel and Related			
Adjusted Operations Expense		***1/8**	

Executive Director: ___________________________ Date: ____________

Chief Accountant: ____________________________ Date: ____________