Hydropower Investment
Promotion Project (HPP)

INITIAL TRANSITION TO HOURLY BASED ELECTRICITY MARKET IN GEORGIA

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USAID HYDROPOWER INVESTMENT PROMOTION PROJECT (HIPP)

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DELOITTE CONSULTING LLP

USAID/CAUCASUS OFFICE OF ENERGY AND ENVIRONMENT

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This document was prepared by

Author	Organization	Contact Details
Ruben Abrahamyan	Deloitte Consulting	abrrub@gmail.com
Reviewer	**Organization**	**Contact Details**
Zviadi Gachechiladze		zgachechiladze@dcop-hipp.ge
Jake Delphia	Deloitte Consulting	jdelphia@deloitte.com
Dan Potash	Deloitte Consulting	dpotash@deloitte.com

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Acronyms Used in this Report

MoE	Ministry of Energy of Georgia
GoG	Government of Georgia
GSE	Georgian State Electrosystem
ESCO	Electricity System Commercial Operator
GNEWRC	Georgian National Electricity and Water Regulatory Commission
MO	Market Operator
GEMM 2015	Georgian Electricity Market Model 2015
ETM	Enabling Trading Mechanism
CBETA	Cross Border Electricity Trade Agreement
PX	Power exchange
MAP	Monthly Ahead Planning – capacities hourly planning for next month
DAP	Day Ahead Planning - capacities hourly planning for next day
DAM	Day Ahead Market
BM	Balancing Mechanism
HPP	Hydro power plant
TPP	Thermal power plant
DC	Direct contract
NTC	Net transfer capacity

1. INTRODUCTION

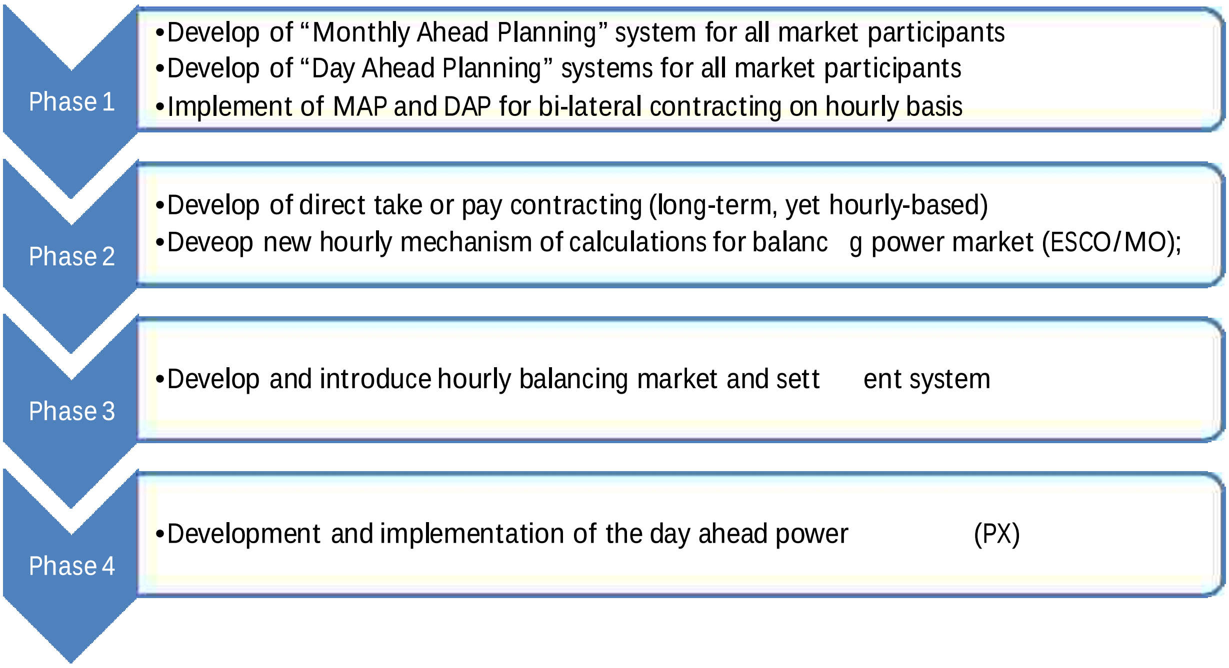
USAID Hydropower Investment Promotion Project (HIPP) in Georgia focuses on the development of new run-of-river HPPs. As part of that assignment, development of the enabling environment for new HPPs is a critical element for sustainable investment. This report describes an initial transitional path to properly functioning electricity trading mechanism in Georgia.

2. PLANNING

The Government of Georgia (GoG)'s, Ministry of Energy Moe's) has proposed to develop the Georgia Electricity Market Model for 2015 EMM 2015), which will be a major step forward in the development of Georgia's com etitive electricity market. GEMM 2015 includes the development of an Enabling Trad g Mechanism (ETM), an important first step that will enable new Georgian HPPs to sell into the regional competitive electricity markets (including selling to ey, pursuant to the Cross Border Electricity Trading Agreement (CBETA) between the GoG d government of Turkey signed on January 20, 2012.)

One of the primary goals of GEMM 2015 is the establishment of an hourly balancing market, before the start of 2015. Georgia's existing electricity wholesale system consists of informal bi-lateral contracts which are backward-adjusted on a monthly basis to account for the actual power delivered. In contrast, ey has an electricity wholesale system that requires participants to make daily forward commitments and be subject to a daily look-back to assess actual energy delivered versus planned. A transition plan is needed for the Georgian power market from the existing "central dispatch and monthly adjustments of bi-lateral contracts" to a new market model, an hourly balancing and settlement system compatible with the Turkish power market.

The transition to this new market model in Georgia should be realized in four phases:



This Report is dedicated to the specific mechanisms of implementing the tasks under Phase 1 and Phase 2, above. In the course of their implementation, the following main factors should be taken into consideration:

- Protection of domestic consumers;
- Creation of incentives for private investors into new Georgian HPPs;
- Creation of favorable conditions for traders for benef cial export of electricity.

Reforms should be carried out gradually, by Phases, as noted above, with the principle of not causing unfair burden on any stakeholders.

In all countries the process of transition to the comp itive market took several years, including the period of development, simulation, and the real implementation of new mechanisms.

This document is developed to justify the necessity an the proposed mechanisms of solution of primary tasks.

2.1 HOURLY PLANNING

The first task is to develop a new system of planning r market participants.

Currently the planning is done on a yearly basis divided by months. The generators and the consumers enter into bi-lateral contracts for electricity delivery volumes. The deviations of the actual volume of electricity from the planned volumes, in theory, are covered by the monthly balancing market through the ES O. In practice, the bi-lateral contracts are not strictly enforced according to pre-determined amounts of energy deliveries.

The main disadvantages of the existing system are the following:

- Absence of a clear system of adjustments to electricity volumes under bi-lateral contracts;
- Unfair and improper calculations of deviations on a mo ly base, when a participant may deviate each hour but have zero deviations on a monthly basis.

The task for Phase 1 is to plan the capacity of each market participant (delivered by each generator and received by each off-taker from contracted generators) for each hour.

All calculations should be performed by daily curves c only used in the power sector, i.e. to plan the next day balance depending on hourly electricity d mand.

Such an approach of planning is usually known as a Day Ahead Planning (DAP). Day Ahead Planning is a key element within the markets functioning in four trading sectors:

- Bi-lateral contracts;
- Balancing Market;
- Day Ahead Market (power exchange):
- Intraday trading Market.

Day Ahead Planning is a set of actions carried out under the coordination of the Market Operator in order to determine their balance of the forecasted hourly market participant nominations for next the day compared to actual deliveries and receipts to the market.

Such markets correspond to the above-mentioned Phase 4.

However, starting from the Phase 1, it would be necessary to determine electricity exchanges for the bi-lateral contracts on an hourly basis. Bi-lateral contracts (or direct contracts as it is called in Georgia) nominations are usually agreed-upon for at least for a month. Therefore, hourly planning is needed for smooth operation of the market for the following month – this is called Month Ahead Planning (MAP).

It does not mean that DAP mechanism is not used in this case. In the proposed approach outlined below MAP and DAP are both used.

2.1.1 MONTH AHEAD PLANNING

A detailed description of a suggested MAP mechanism is presented in Annex 1 of this document. The main body of this report provides a description of the main tasks of MAP development process, to get to the MAP mechanism.

This proposed mechanism was discussed and was agreed-upon by ESCO.

The proposed mechanism consists of the following:

- Receive and filtering of historical data (1-3 years) on purchase/sale of electricity
- Sort by selected typical days
- Define the averaged shape of the curve for each typical day of the month
- Adjust for the difference between electricity volumes by averaged typical day, the weekly dynamics of changes of electricity volumes, and the synchronization of planned and historic years' calendar. The calendar synchronization requires applying and adjusting the current year's weekdays, we ends, and holidays, onto usage periods from the past.

As a result of this process, we receive weighted coefficients for each hour of the planned month and multiplying them by the planned monthly volume we receive planned capacities for each hour.

The advantage of the suggested mechanism is that calculation data are used in per unit values and not in absolute values; this allows using such shapes of the curves, which are rather realistic for the majority of market partic ants (consumers, run-of-river HPPs, medium and some large HPPs) and do not depend on a number of factors (water levels, climatic conditions etc.).

For the realization of this mechanism, special softwar should be developed and modeling should be initiated. If, as a result, it beco es clear that for a number of entities this approach does not provide adequate results (for e ample, for the Enguri hydro plant), then a specific mechanism should be developed nd applied hereto.

Hourly bi-lateral contracts (which are the majority of the contracts) will be concluded for the month ahead. (See below).

2.1.2 DAY AHEAD PLANNING

The DAP implementation will improve the accuracy of pl ing for a particular day. The procedures for such planning were developed in the fra ework of the HIPP project (a previous HIPP developed document).

MAP curves can be used as initial data for the DAP for the planned day. The adjustments of these curves will quickly allow developing the necessary contract capacities for each hour.

The result is the planned curves of market participants for the (N+1) day, where N is the current day.

DAP as MAP involves a series of steps, as follows:

- Submission of offers by market participants;
- Preparation of hourly balances by Market Operator, adjustments (when necessary) agreed with concrete participants;

- Ø Regimes verification on the technical feasibility by TSO with possible adjustments;
- Ø Final regime by hours;
- Ø Contracts conclusion between market participants (in c se of DAP daily contracts with ESCO (trader) must be added).

In this case, the time allocated for the DAP is very limited, especi in the first stage taking into account the absence of hourly market funct g experience for many participants. In this case, consideration may be given for DAP for the (N +2) or (N + 3) days.

3. BI-LATERAL CONTRACTS ON HOURLY BASIS

According to the approved GEMM 2015, it is necessary t develop new principles of bi-lateral contracting between Georgia's wholesale market participants.

Currently such bi-lateral contracts, referred to as "direct contracts," are executed on a yearly or monthly basis for electricity volumes. This mode of bi-lateral contracting has a significant disadvantage, as follows: If in the monthly profile, the actual volume of electricity of a market participant coincides with the contractual volume, then the purchase of that volume from the balancing market will be zero. However, a monthly deviation of zero does not mean that there were no hou ly deviations. If there are hourly deviations, this may seriously deteriorate the power system regime as a whole.

As a result of not capturing hourly deviations, an entity having a negative impact on the regime, and on the functionality of other participants, does not bear any responsibility.

While implementing the new market model operation on h urly basis, it is required that several new mechanisms, in particular direct contracting for the monthly (but on an hourly basis) must be developed and implemented.

New contracts should operate on a "take or pay" principle and not be backward-adjusted, as is the case in the today's practice.

Take-or-Pay principle means that a buyer is responsible to pay for a good or a service whether or not it was in fact delivered.

Another important point is to determine where such contracts are concluded. As a result of discussions with ESCO the point of c nclusion is at a generator's node as was earlier.

A reasonable question arises what volume of electricity (net generation or consumption) must be included in a bi-lateral contract:

1. If this is a consumption, then the losses must be paid in addition (curren they are paid through the transmission or distribution tariffs).

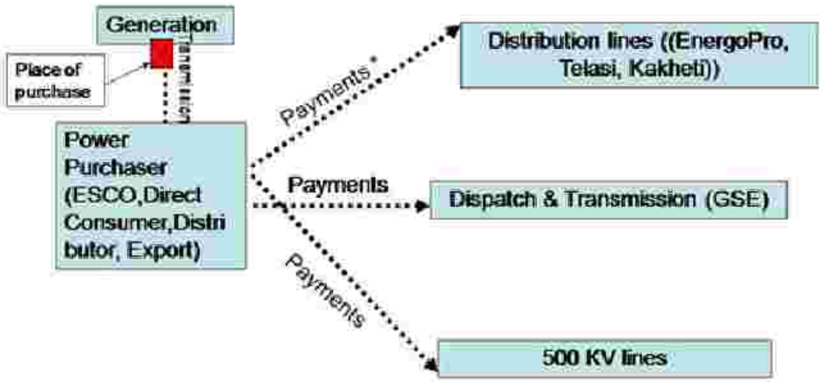
2. In the case of concluding contracts in terms of net generation the losses caused by the consumer should be added to consumption.

Further consideration of approaches to allocation of losse presents options for discussion with all interested parties.

Electricity market of Georgia is characterized by financial contracts rather than physical. As shown in Annex 2 for such market the physical method of allocation of losses is unacceptable, which leads to a need for another methodology development.

The current practice is to cover losses in the market sportation expenses as they are called by ESCO) through the transmission tariff (yearly).

Fig. 3.1.Existing payments schedule



When a market buyer purchases electricity, they must p y transmission tariff (if they are connected to the transmission network) and they must p y transmission tariff and distribution tariff (if they are connected to the distribution system – the users pays the distribution company, who, in turn, pays the transmiss on company). The network tariffs include an average level of losses. At the end of the month, the TSO calculates actual transmission losses for delivery to directly connected consumers, distribution networks and exports. In the monthly settlement process, the differences in collection of losses in tariffs (volume and prices) are reconciled in the invoices to the transmission users. DSO losses are handled differently, where annual adjustments are made not for volume, but for generation price differences. Only nor ative losses are used in DSOs.

However, such approach has some disadvantages. For example, a consumer can be connected to the transmission network via a very short distribution line, but must pay an additional distribution tariff, which will significantly reduce its competitiveness on the market and will not provide incentives for market entry.

With consumption increase additional losses are created. They should be paid at a specified price, but, depending on the network which creates these losses the user is connected, the cost of losses can be different.

There is no mechanism for determining the consumer lev l of responsibility in the change of losses (sometimes the dispatcher is responsible).

It is clear that the application of long-term transmission and distribution tariffs and the actual structure of the generation at the stage of bil eral contracts and balancing mechanism may lead to financial imbalance.

Thus, when adopting this method (used in several countries) it's necessary to examine all possible cases and to develop specific mechanisms ing into account the specifics of Georgian market.

In this paper we attempt to offer an alternative approach to allocation and payment of losses, free of the most of the disadvantages mentioned above.

Transmission and distribution tariffs in principle can be divided into two parts that will reflect the operating costs and the cost of losses.

Under the proposed mechanism only payment of losses will be discussed, operating costs will be covered similar to the existing practice by the relevant tariffs that do not take into account the loss component.

The main difference of this approach is to abandon the traditional network division into transmission and distribution ones.

We introduce the notion of "market network", which is determined by the network limited by points of sale / purchase of market participants.

The losses in this network are the differences between the net generation and consumption. ESCO on its website calls them "transport on expenses". In this study we will call them "market losses".

This mechanism allows differentiating losses in the di erent sectors of trade by the price and the degree of responsibility of each consumer.

One of the principles of the proposed method is the fa allocation of losses and ensuring equal conditions of competition for market participants.

In this study a mechanism for payment of losses directly from consumers is proposed.

In the framework of this project a methodology of fair losses allocation was developed and proposed, however for the first stage ESCO decided to use losses allocation based on average percentage by months (see Annex 2).

Thus, further discussion will be based on this approach (in t s case it will be necessary to amend the GEMM 2015) which must be negotiated with all the stakeholders.

In applying this approach, a bi-lateral contracts will be concluded at the point of ne generation by volumes consumption times ($1 + L_h$), where L_h – share of average market losses.

It should be noted that this approach assumes that consumers connected to the transmission network will have somewhat greater financial burden than in the approach above; however, it won't be a big difference, taking into a count that market participants mainly buy only a part of electricity through the transmission network. But at the same time you can avoid the "unfairness" associated with th rical structure of the power system and to create incentives for consumers connected to the distribution networks for direct entry to market.

Using such approach the price of losses on bi-lateral contracts for each hour will be determined by the structure of generation of planning regime based on a structural analysis (see Annex 2).

The allocation of losses and their prices for balancin mechanism will be given in Chapter 3.

Let us consider the possible models for the conclusion of bi-lateral contracts.

Three basic modes of direct contracting for electricity are possible:

1. Full pool;
2. Partial pool + free negotiation amongst market partici ants on a monthly basis.
3. Partial pool & free negotiation among participants on a monthly basis + daily contracts amongst market participants and ESCO;

The disadvantages of Model 1 are:

- Ø It is necessary to export power on a monopoly basis, but it contradicts existing legislation;
- Ø Lack of opportunity for market participants in selecti n of a financing partner;
- Ø Possibility of requirements for small HPPs to sell 100% of electricity in summer at low prices;
- Ø Disabling the use of export as an incentive for investors into construction of new HPPs in Georgia;
- Ø The necessity of having highly accurate hourly MAP planning for bi-lateral contracting;
- Ø Mutual influence of MAP planning accuracy of one participant on other participants.

The disadvantages of Model 2 are:

- Ø Is that doesn't allow for the covering of all consumption in each hour
- Ø It conflicts with the terms of the first stage of the reform.

M**odel 3** appears most feasible and is considered below in more detail.

There are two proposed types of contracts for planning month.

Type 1 Partial pool (full matrix)

The main purpose of this type of bi-lateral contracts is to minimize the generation price for domestic customers and also the allocation of this generation b een all domestic consumers “fairly by volumes".

At first the generators that participate in this schedule must be selected (their composition can vary by the seasons).

For example, for the summer, when TPPs of Georgia are not operating, the schedule may include only Enguri, Vardinili, etc. (i.e., low cost electricity production).For the winter, when Georgia has a shortage of electricity, th TPPs can be included in this schedule to allocate fairly the expensive electricity among all consumers.

In this mechanism two steps are suggested for realizat on.

Step 1 - selection of those generators, which mandatorily shoul participate in the Pool.

Such generators over the whole year are Enguri, Vardin i and probably Jinvali HPPs as state-owned generators of inexpensive electricity at tariffs approved by GNERC. In this way the protection of domestic consumers will be ensur d.

In winter period, when there is deficit of electricity in Georgia, operation of TPPs and import activities are unavoidable. This gas or oil-generated electricity is expensive, however, including the TPPs’ generation and import electricity into the partial pool will allow to fairly distributing it between off-takers.

Step 2 - With application of this approach, the electricity generated hourly by each of these generators shall be distributed between the consumers according to their portion of total consumption (the principle of full matrix).

As a result we will get the same generation price (for each hour it will be different) for the wholesale consumers under these contracts.

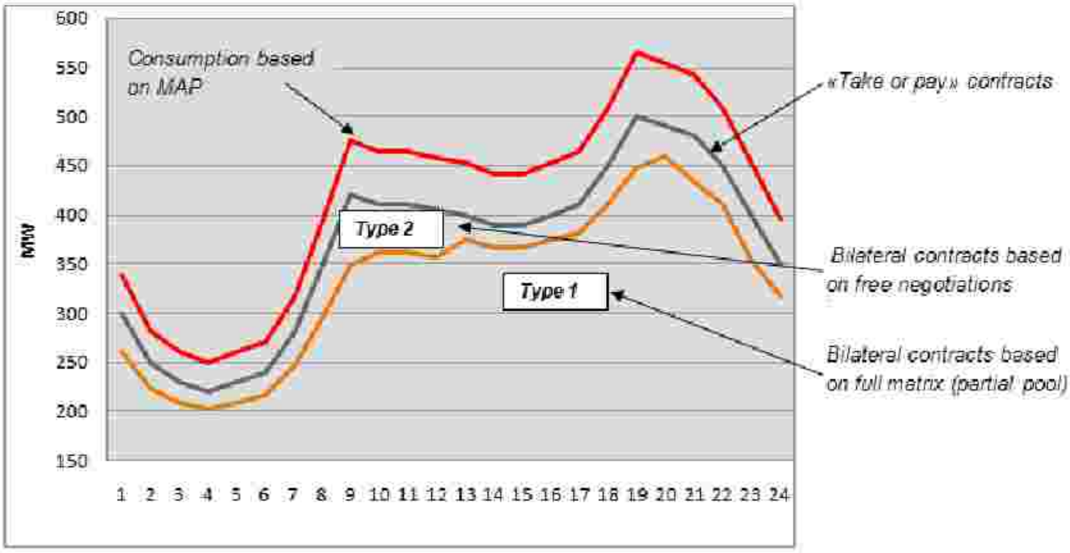
It is worth mentioning that electricity off-takers having their own generating plants (e.g. EnergoPro, Telasi) participate in this scheme with the ortion of consumption defined as consumption minus own generation in summer and consump on in winter (TPPs and import portion increase).

Type 2 Free negotiations between market participants

This type of contract corresponds to today's practice, but in the future, they should be on an hourly basis.

There is a high probability that the sum of these two pes of contracts will not cover 100% of planned consumption (Fig .3.1).

Fig. 3.1 Contracts on monthly basis



In this case, the contracts that will cover the gap between the planned consumption and the volumes by contracts of types 1 and 2 are needed.

Such monthly contracts could be concluded between the ket participant and ESCO (trader), which would have to buy additional generation, cluding imports, and would sell to the consumers.

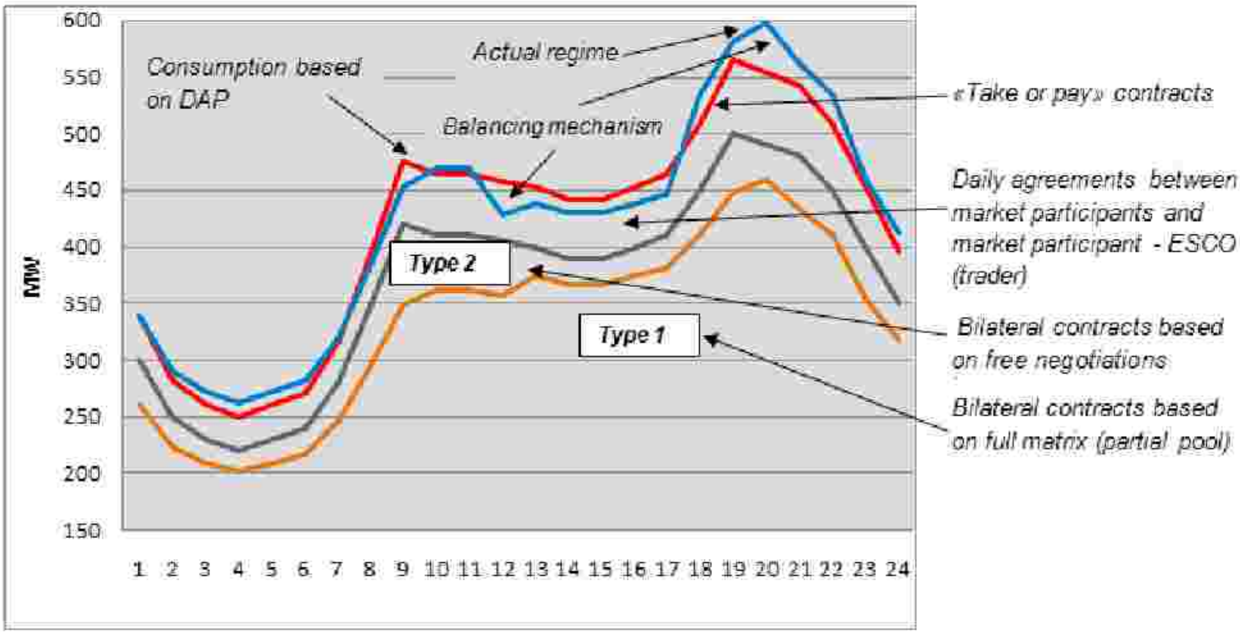
There is another option, in particular, the conclusion of such contracts (agreements) for a planning day using DAP, which will more accurately determine the need for a specific day, that is very important from the point of view of e contracts based on a "take or pay" principle.

As a result of discussions with ESCO this option was a opted. Moreover ESCO's wish is to provide the possibility of concluding such daily contracts between market participants too.

In this case, there is a high probability of 100% cove age of the daily consumption through bi-lateral contracts (practically 4 types of contracts, 2 – based on MAP and 2 – based on DAP)

Fig. 3.2 summarizes all types of contracts where instead of a MAP curve (Fig. 3.1) appears DAP curve (red line).

Fig. 3.2 Contracts and balancing



Such combination of contracts on the monthly (relative y long-term) and daily basis is the optimal one.

Monthly contracts allow the participant to optimize a participant's portfolio in advance.

Moreover the lack of a unified regional market will pr vent conclusion of export/import contracts during the day.

The presence of the contracts on a daily basis will increase the accuracy of planning and minimize participation in the balancing market, where prices are higher.

In reality the market participants cannot operate only in accordance with the signed bi-lateral contracts so deviations are inevitable.

4. BALANCING MECHANISM

According to GEMM 2015, the first Stage does not include the implementation of the system of bids and offers with prices, which does not low for the possibility of the full-fledged functioning of the balancing market.

In any case, if a market participant actually acting on power market deviates from electricity volumes scheduled by bi-lateral contracts, it becomes a balancing market participant. And depending on the sign of that deviation, the Seller may become a Buyer and vice versa.

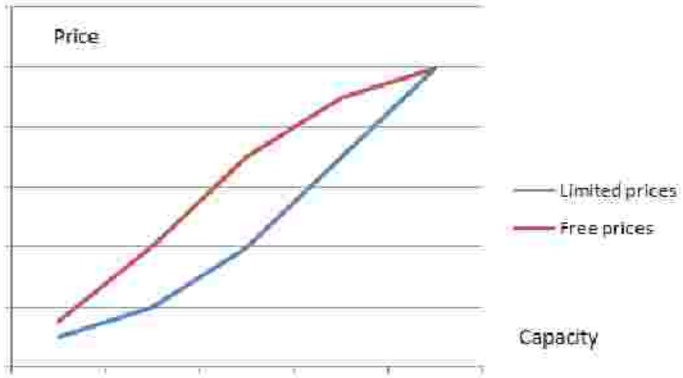
For example, the generator that produced less than the planned me should purchase supplementary energy on the balancing market the consumer that reduced its consumption can sell the surplus.

Thus it will not be balancing market, but so-called deviations market.

The decision of a balancing mechanism without bids on e first stage is absolutely correct, because in case of lack of competition in the market, the generation price on market will rise sharply because of the generators des re to participate on balancing market instead of trading with bi-lateral contracts.

This is due to the fact that HPPs understand that with bids that are a little lower than TPPs' and import prices, they will fall into balance, specially in winter. At the same time, the price for HPPs can be significantly higher than their regulated ariff. This will result in an outcome shown in Fig. 3.1.

Fig. 4.1 Prices on balancing market (example)



What is being done now?

For each market participant, the deviation from the planned value of bi-lateral contracts (after adjustments) is provided on a monthly basis - single value.

Then average monthly balancing price is determined bas on generators participation and their fixed prices on a monthly basis – single value.

ESCO bills the amount for each market participant determined by simply multiplying these two values.

The main disadvantages of this mechanism are:

- Bi-lateral contracts adjustments affecting the magnitude of the deviations;
- There is no mechanism for determining hourly deviations, which results in a significant difference between actual deviations and e timated monthly deviations;
- No mechanism exists to determine hourly prices, which ctually equates deviations at night and peak;

- There isn't difference in prices for small and large deviations that lead to balancing price increase.

All this allows concluding that used balancing mechanism is imperfect.

The new balancing mechanism being developed should exc e these disadvantages.

Balancing electricity (capacity) will be the difference between the actual regime and the sum of bilateral contracts concluded by hours that as entioned above are not subject to adjustment (Fig.3.2).

Consumption deviation (balancing electricity) for cons er ***Djh*** for each hour ***h*** is defined by the following algorithm

$$DC_{jh} = P_{ajh} – P_{bjh} / (1+L_h)$$

where DC_{jh}– consumption deviations on border of consumer j;
P_{ajh} – actual consumption for consumer j;
P_{bjh}- sum of bi-lateral contracts of consumer j;
L_h – average losses portion in p.u.

$$?L_h = G_{ah} – G_{bh} - ?_j DC_{jh}$$

where $?L_h$– additional actual market losses due to deviations in MW;
G_{ah} – sum of actual system generation;
G_{bh} – sum of generation by bi-lateral contracts

$$?D_{jh} = ?L_h * DC_{jh} / ?_j DC_{jh}$$

where $?D_{jh}$– additional losses covered by consumer j

$$D_{jh} = DC_{jh} + ?D_{jh}$$

The important point is to determine the degree of responsibility for each participant and dispatcher for each deviation (the reason, sign of the deviation), which will be expressed in an appropriate fee for the deviation for what it's ssary to develop the appropriate pricing system.

The methodology for determining prices for the balancing mechanism will be developed as part of an integrated system of pricing for the ref ed Georgian market (see Section4 below).

5. PRICING

The ongoing reform should be based on the principle of "not to harm." It primarily refers to the price of generation for domestic consumers would not be any higher with this initial transition as opposed to the prices without it.

In no competition conditions (most of the year, Georgia is deficient or must use the old units at TPPs), the liberalization of prices will lead to their rapid growth. The limitation of the increase or even the decrease of prices is possible due to the competition, which is possible either in case of construction of new efficient power plants or by introducing mechanisms to limit prices.

Thus, at the first stage of the reform, such a pricing system should be designed that will limit the growth in prices.

5.1. PRICING OF BI-LATERAL CONTRACTS

5.1.1 PARTIAL POOL (TYPE 1 OF CONTRACTS)

Selected generators must participate in a partial pool with their regulated tariffs, at that the Enguri and Vardinili HPPs must sell practically all volume of electricity in this sector. Of course the spinning reserve services offered by the e units must continue and not be restricted by the bi-lateral electricity sales and purchase agreements.

Taking into account that approved tariffs for existing medium-sized HPPs are also relatively low they must have the rights to address to Market Operator for participation in the partial pool, leaving to them the absolute possibi y of contracting by free negotiations.

Existing small HPPs can also exercise this right, the only difference is that they have to negotiate for the price with Market Operator as their pproved marginal price is quite high and in the summer this electricity may not be dem ded in the domestic market.

The main incentive for investment in new power plants is the possibility of electricity sale to the Turkish market. However, it is not a fact that all new power plants will be able to sell electricity for export. Considering the need t attract investments in the construction of new power plants and the lack of feed-in tariffs, it is necessary to consider the possibility of participation of new plant in the partial pool with predetermined prices differentiable by seasons.

The consolidator(s) (proposed in 2015 GEMM) also must be able to participate in the partial pool at prices negotiated with the Market Operator. Under the existin law, only ESCO is allowed to buy from generators and resell inside Georgia.

5.1.2 Monthly contracts between market participants by direct negotiations (Type 2 of bi-lateral contracts).

This case is characterized by the absence of restricti on the offered price, and if for some reason a consumer wants to buy additional, but mo e expensive electricity, the generator can sell it.

However considering that the consumer has the opportunity to purchase more electricity also on "daily" market, it is unlikely that negotiated bi-lateral contract prices will be higher than the regulated tariffs for generators.

5.1.3. DAILY AGREEMENTS (CONTRACTS).

As mentioned above this type of contract, providing to cover the difference between the DAP and the volume of bi-lateral contracts on monthly basis for a particular da is also an element of a "planning" market. The variation of th se contracts is the possibility of ESCO participation as an electricity trader.

On the "daily" market negotiated prices or the prices not exceeding regulated tariffs will be realized.

Generation price minimization can be reached by 100% coverage of planned consumption through bi-lateral contracts.

5.2. BALANCING PRICES (DEVIATIONS MARKET)

Prices on balancing trade sector will be higher than by bi-lateral contracts for the following reasons:

- A large share of participation in balancing includes m e expensive generators (TPPs, import);
- Lack of sufficient surplus of relatively low-cost generation on Georgian market.

This fact is an incentive for consumers to improve the accuracy of planning and minimal participation on deviations market.

On the other hand, it may lead to a situation when generators will seek to sell more electricity on balancing market, reducing its offer on the market of bi-lateral contracts, which will lead to an increase in generation prices for domestic consumers.

Moreover, under the action of bi-lateral contracts on a "take or pay" principle, a consumer can request large volumes for bi-lateral contracts and sell surplus electricity on deviations market.

To avoid these risks certain mechanisms must be implem ted:

- **Firstly**, it is necessary to determine who initiated this devi (a market participant or dispatcher). Namely the responsibility or the deviation determines the payment. Note that the dispatcher has no means to y, but in almost all cases, the market participants are responsible for deviations, i.e. deviation of one of the participants is determined by the deviation of thers. For example, if a consumer increases its consumption, whereby the dispat er commands to increase electricity generation, the consumer is responsible for this deviation. The only case where the responsibility lies on the dis atcher is the load redistribution between the generators (altering the di patch schedule).

The basic approach in setting the price for the deviat   must be the principle that no additional financial burden is put on the market participant if it works on the planned schedule, or obeys the dispatcher's command.

- **Secondly**, the introduction of commercial dispatching is necessary, when a dispatcher within the technical constraints leads generation regime in accordance with minimal costs (this solves the problem of generation redistribution).

  The larger a consumer deviates in the direction of increased load, the higher the balancing price on the deviation market will be.

  The desire to minimize this price in the absence of compet on and pricing bids provides a basis for limiting the price of generators   the approved level. An exception can be made for new power plants, and maybe xisting small HPPs for which the use of pre-defined capped prices is allowed that will be an incentive for investors.

- A possible option of the prices with a small step-up ratio used for generators (incentive for additional generation) would require im osing restrictions on the amount of electricity generated for balancing for the of these generators participation in bi-lateral contracts.
- If the consumer will plan an overestimated volume on the bi-lateral contracts market (cheaper market)in advance, and as a result wil have a surplus that will be able to realize on the deviations market in order to extr t additional profit, it is proposed to limit the opportunity for this consumer by allowing it to offer electricity to deviations market at price of partial pool multiplied by the reduction coefficient (e.g. 0.90-0.95).
-

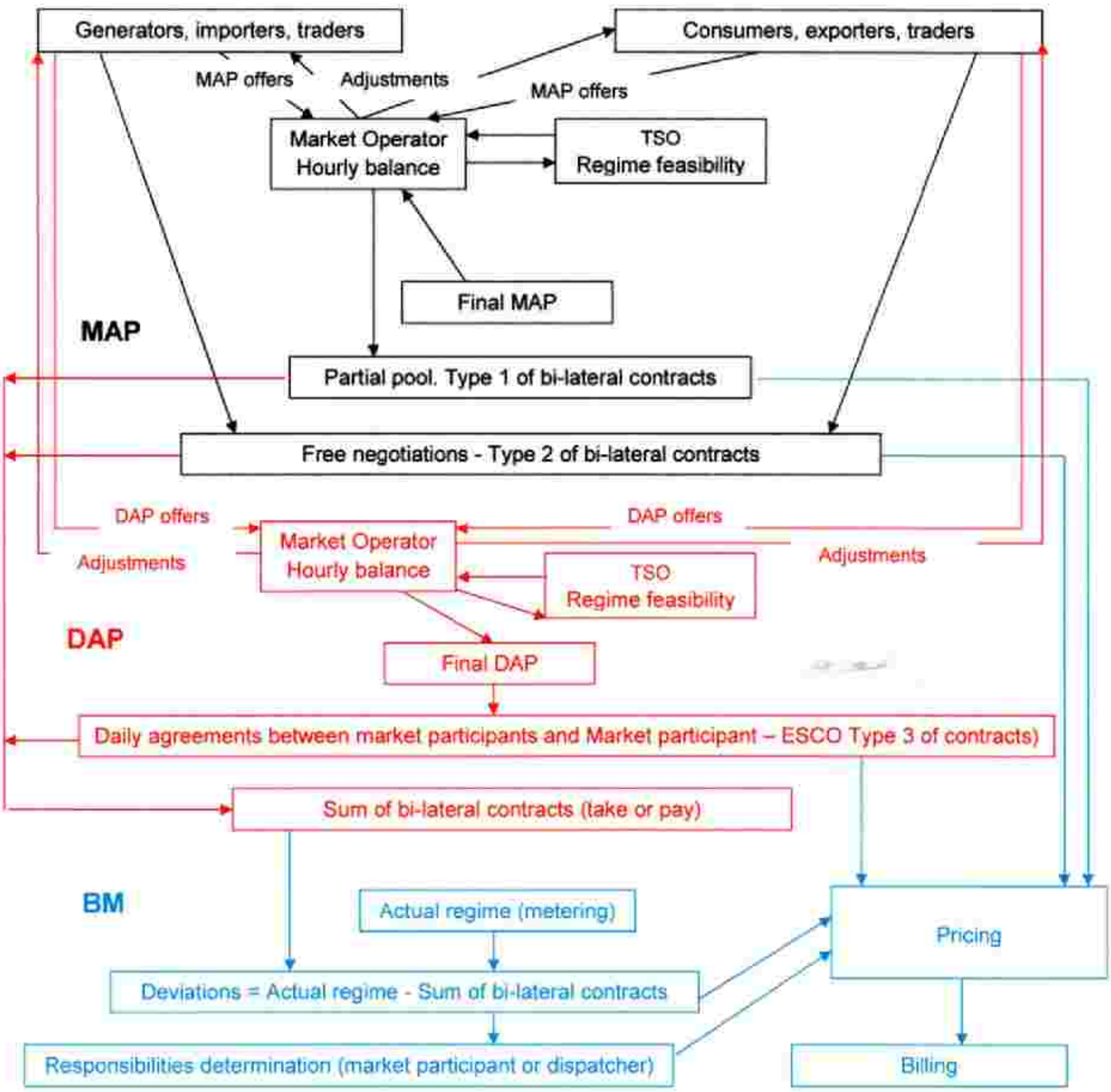
5.3. PRICE OF MARKET LOSSES

The mechanism of bi-lateral contracts conclusion at the point of net gener tion based on the average percentage of losses on market adopted at this stage of the r form determines the required payment of losses as well. Extra charges are not needed.

Applied mechanism for the deviation determination (Cha er 3) includes additional losses, their allocation among consumers and they are ctually charged by balancing price for each hour (included in deviation). Extra charges are not needed.

In case of rejection of this approach it's necessary t develop a specific mechanism as was mentioned above.

6. Model for initial transition to hourly market



Annex 1.

Monthly Ahead Planning

1. Algorithms

Period of planning.

According to the suggested methodologies, a month could be selected as a period of planning

Splitting by types of days

Considering the different levels of consumption by day week, planning should be implemented with consideration of this factor.

For example, Working Days, Saturdays, Sundays & holidays could be selected as typical days.

It will probably make sense considering dispatchers' typical practice, to divide working days into Mondays and Tuesday-Fridays.

If necessary each day of a week could be considered as a typical day (the suggested methodology should not have limitations).

Availability of initial data

The metering database currently installed at GSE is unfortunately not completed yet but it is the only source of obtaining historical data required for these methodologies.

It is necessary that while using AlphaCenter (metering database and software) the meter readings be grouped in such a manner that for each market participants one value be received by each hour (capacity).

Based on the existing information held by GSE, developing hourly electricity accounting by hour is possible and will it involve all market participants included into the mete g system.

Looking ahead, we may say that the absolute values of capacities will be not used in calculations for the initial operation of MAP, but rather the shapes of daily load curves. This will allow reducing the impact of missing meters.

Thus, the MAP development and the metering system development may proceed as parallel processes.

The details of the required historical data

The number of previous years to be used in the analysi could be from one to three years.

The methodology should allow varying this indicator. On one hand, the more the information, the better is the result, because more data will allow considering the difference between years, for example, different weath r conditions and “water levels”; on the other hand, the closer the given year to the pl nning year, the more considerable it may become from the viewpoint of accuracy of the results.

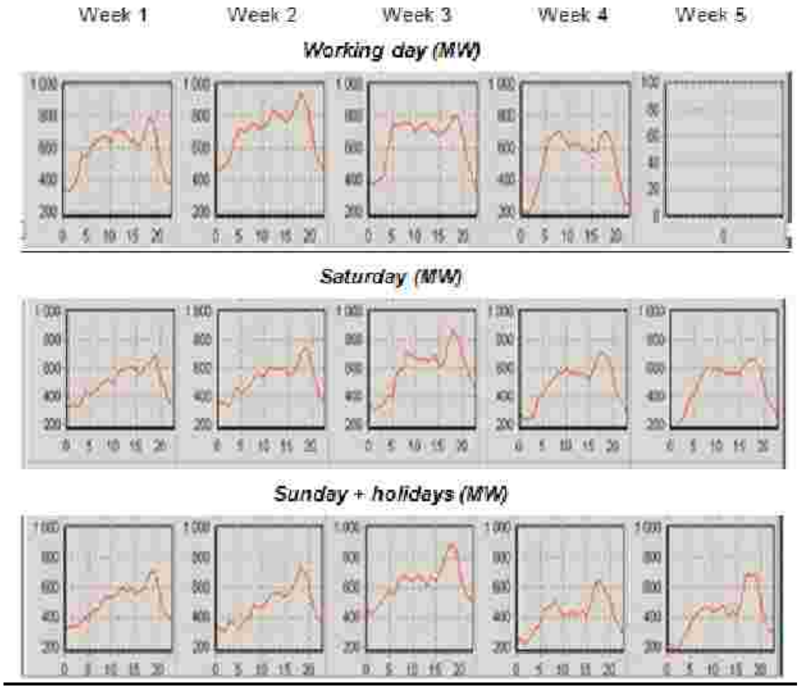
Suggested methodology

The idea of the approach and the phases of planning are as follows:

1. Processing of historical data

   At the beginning we would suggest an example, when only the past year is considered for historical data. Hypothetical data were used for illustration (figure below).

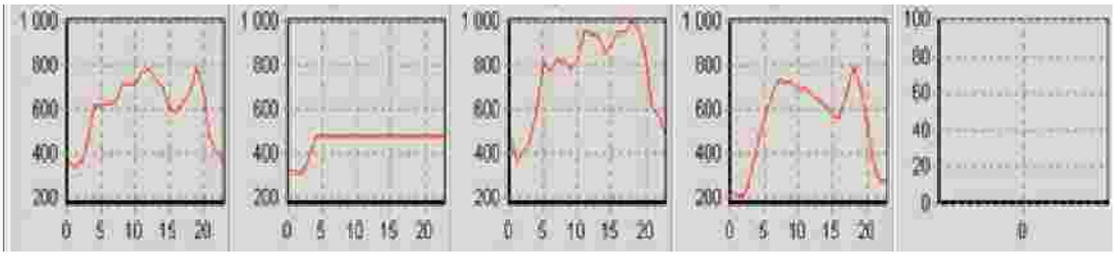
   Figure A1.1. Examples of Daily Load Curves



For each typical day of the month under review, the shape of curve in per units is defined as the value of energy of a specific hour in r lation to the sum of daily values of energy of all days of that type.

If any diagram falls out of the given pattern, for exa ple, due to failure of a meter, it should be excluded from the calculation (figure Fig. A1.2). In this example the second diagram falls out and should be excluded from the analysis.

Figure A1.2 Data filtering



In this connection it is necessary that the quality of the historical information be analyzed prior to the identification of shapes of the rves.

After these steps we can obtain a shape of the curve f each type of a day of the month under review.

In the case when several years of historical data are eviewed, the forms of curves are defined for each year separately and then they are averaged.

2. Calculations of hourly curves for market participants for the planned period

Currently only monthly volumes of electricity are being planned for each market participant. The task is to divide this one number in MWh into each hour of the month in MW.
The main task will be to identify the weighted coefficients by each hour of the planned month.
Based on the analysis of historical data we will obtain the average weight coefficients for all types of days for each hour

$$@_{@} = \frac{@^{@}_{(@@}@_{@}}{@^{@}_{(@@}@_{(}} \qquad (1)$$

t – type of a day, t = 1, …..,f;
f – number of typical days over the historical month;
i- hour, i=1, ….,24;
n – number of t-type days over the historical month;
K_{ti}–weight coefficient for the hour i of the averaged curv of the typical day t over the historical month;
E_{ij}– volume of electricity at hour i of the j^{th} day of type t over the historical month;
E_j – volume of electricity of the j^{th} day of type t over the historical month

This does not mean that their direct application is possible for obtaining the weight coefficients by each hour of the planned month due to the following reasons:

- Different volumes of electricity for different typical days;

- Different weekly volumes (for example due to weather factor);
- Different number of typical days in the planned and retrospective months (calendar synchronization is needed).

First of all we shall calculate the relation of the electricity volume between the typical days. For this we shall calculate the aggregate electricity volume of typical days in the historical period, and then divide it into the number f days of that type. As a result we will get the average volume of electricity by each typ of a day.
Then we shall define the “daily coefficients” as a rat of the historical electricity volume of each typical day for example to the working days.

$$@_{(} = \frac{@^{@}_{(@@}@_{(}/\ @}{@^{@}_{(@@}@_{(}/\ @} \qquad (2)$$

K_t – daily coefficients of the relation between daily average volumes of electricity on typical days and the daily average volume over the first day type of the historical month;
t = 1, ….,f
n – number of days of first type over the historical month;
m – number of days on each type of day t over the historic month;
E_j – daily volume of electricity over the j^{th} day of the historical month

The received average historical weighted coefficients y hours shall be multiplied by daily coefficients depending on the type of a day.
This will allow considering the averaged weight coefficients the difference between energies of the typical days, for example, between a S urday and a working day. Thus, the weight coefficients in per unit of various types of days become reduced to one base by energy.
Note: the sum of weighted coefficients by typical days, except for the working days, will not equal to 1.
The changes of volumes by weeks should be also conside For this reason a notion of “weekly coefficients” is used
Considering that some of typical days (e.g. Saturday) re once in a week and may not give a clear tendency of a weekly change, as a weekly oefficient the ratio of an average day for the given week to the average day of the first week can be used (historical).

$$@_{(} = \frac{@^{@}_{(@@}@_{@}/\ @}{@^{@}_{(@@}@_{@}/\ @} \qquad (3)$$

K_l - ratio of an average day for the given week to the aver ay of the first week

$E_{@}$– daily electricity volume for l^{th} week;

a and b – number of days in l^{th} and first week respectively

How can one use the above mentioned coefficients for the planning period?
The portion of each hour in the volume of electricity or the planning month should be defined.
The product of three corresponding coefficients for each day of the planning period should then be calculated.
For example, if one assumes the first day of the planning period is Saturday, then K_{ti} corresponding to the average Saturday for 24 hours sha be selected. Then these coefficients shall be multiplied by K_t (see above) representing the ratio of the average Saturday energy to the average working day energy over the retrospective month.
Then this product shall be multiplied by a weekly coef cient K_l corresponding weekly coefficient shall be selected for planning day of month defined as a ratio of historical volume of electricity of average day of each week to 1th week.
With this, all coefficients by each hour of the planning month K_h are calculated.

$$@_@ = @_@ \times @_@ \times @_@ \qquad (4)$$

h= 1, …….,d;
d – number of hours in the planning month.
The sum of these coefficients will not equal to the sum of days of the planning month, therefore to calculate the portion of each hour A_h in the energy of the planning month we should calculate the following:

$$@_@ = \frac{@_@}{@^{@}_{@@@} @_@} \qquad (5)$$

These received coefficients $@_@$ are final for the planned month.
Multiplying the planned monthly volume by the $@_@$ the planned capacities for the whole month by hours are obtained.

In case of necessity to determined different curves fo working days of the week (should be discussed from the perspective of further market de   opment in terms of direct contracting), an additional mechanism of splitting weekly volumes by days could be applied, as a result of which each working day of the w   k will be similar by the shape of the curve, but different by the volume.

Let's consider several factors that may impact the rea y of obtaining planned hourly schedules.

The suggested MAP algorithm could be applied for all consumers without any limitations.

While defining daily curves for generators, it is necessary that the limitations by minimum and maximum capacities be taken into account.

Theoretically, difficulties may occur while planning power plants regimes.

The problem for generators is that splitting of the planned volume of electricity according to the certain shapes of curves may result in the following situations:

1. Increase of capacity above the technically allowable m ximum at peak hours;
2. Decrease of capacity below the allowable minimum at ni hours.

Considering the load growth tendency in Georgia, as well as the envisaged exports to Turkey under the current limited surplus of hydro gene ation in summer (350-400 MW), the second option could be practically excluded.

It worth mentioning that for run-of-river HPPs the first situation is also hardly probable.

What relates to the large regulating HPPs, then, though this possibility theoretically exists, it could be probably avoided, meaning the current rehabilitation of the Enguri HPP will bring to the increase of the allowable capacity.

Construction of new HPPs may as well remove this problem.

Even if a market participant faces such a situation, then one of the two following mechanisms could be applied for the first situation in order to put the regime into the allowable range:

- Ø To reduce the planned volume of electricity by preserv g the shape of the daily curve;
- Ø To re-dispatch the volume of electricity that goes beyond the technical limitations range on the other hours of the day (the daily volume ains unchanged while the shape of the curve is distorted).

So, what needs to be done?

First of all, it is necessary to evaluate the probability of occurrence of such cases. This confirms one more time the necessity of developing the aforementioned software and performing specific calculations.

If the problem anyhow occurs, it will be necessary to evelop special activities

The reviewed options relate to the market participants, for which the shapes of curves are slightly changing year by year. These participants may include consumers, run-of-river HPPs, HPPs with some reservoirs.

With certain HPPs of Georgia, for example, Enguri HPP, problems may occur, however, the final answer could be received only after the analysis of real historical regimes. This will require using data from the above mentioned “commercial ering database” of GSE.

If it becomes clear that the regimes differ significan , then for this group of entities special mechanisms should be developed. For example, considering the availability of experienced specialists on regimes planning (in particular water regimes) in appropriate divisions, the data calculated and sent by these speci lists could be used as planning data.

3. Coordination of daily planned curves between ESCO/MO a rket participants

At this first phase of MAP it is assumed that the calculations of planned curves will be performed both by market participants and ESCO/MO based on GSE metering data due to availability of a centralized database and the necessity to create special software based on that database, as well as availability of exp enced specialists, etc.

Once the results are received they should be coordinat d and adjusted between market participants and ESCO/MO, since a balance of the system as a whole needs to be conducted by ESCO/MO.

Once software is developed and installed and the participants are trained, market participants will perform the planning.

As a result we will have mutually coordinated daily planned curves.

The received MAP curves should be checked for technical feasibility and, if violations of relevant limitations are revealed, new adjustments should be introduced.

4. Regimes feasibility test and adjustments

The purpose of this module is to test the planned regime for the whole pow r system on the feasibility. This applies mainly to restrictions f the transmission, which should not be exceeded. In other words, we need to understand wh ther the dispatcher can lead the regime to satisfy the planned capacities for market participants or each hour..

This test is in general focused on the calculation of transfer capacities (NTC) based on application of software for load flow and stability calculations, for example, PSS/E.

If, for some lines the restrictions are violated it’s nece sary to adjust the values of the planned capacities for these hours for relevant market participants,

This review should be performed exactly in the planning stage, so that no further problems with the direct contracting, which should be concluded on the «take or pay» principle (see below).

This module is important from the point of view of further implementation of Day Ahead and Balancing Markets also.

2. Example

Let's consider as an example a consumer with daily peak consumption.

The historical hourly data on purchase of electricity re presented in Table A1.1 (one year is taken as a retrospective period).

Based on these data the averaged curves of consumption by typical days are defined (Working days, Saturdays and Sundays & holidays are taken as typical days), represented in MW (Table A1.2) and in portions of each hour in the daily consumption by formula (1) (Table A1.3.).

Then, the daily coefficients for typical days under type 1 are defined by formula (2). The following coefficients are received: for Working days - 1.0, for Saturdays – 0.9723 and for Sundays & holidays – 0.8743.

The following values for weekly coefficients are calculated by formula (3):

1^{th}week	2^{th}week	3^{th}week	4^{th}week	5^{th}week
1.0	1.0083	0.9876	0.9722	0.9832

Then, considering the synchronization calendar for the planning month the values of K_h for each hour of the planning month are calculated by ormula (4) (Table A1.4, the values are presented as K_h*10^2). The sum of all K_h in our example is 30.17. Dividing each K_h by 30.17 we receive A_h by formula (5), i.e. the weighted coefficients of each hour in the consumption of the planning month and mult ing these coefficients by the planned volume of monthly consumption (in this example it is assumed to be 22000 MWh) we receive the planning capacities by each hour Table A1.5).

Table A1.1. Metering data of historical month in MW

Days	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31
	T	We	Tue	Fri	Sat	Su	Mon	T	W	Tue	Fri	Sat	Su	Mon	T	W	Tue	Fri	Sat	Su	Mon	T	W	Tue	Fri	Sat	Su	Mon	T	W	Tue
00:00-01:00	26.5	26.7	26.9	26.5	26.9	25.9	25.4	26.8	26.8	27.2	26.1	27.1	25.5	25.1	26.2	25.7	26.0	26.3	27.2	25.8	25.1	26.5	26.1	25.9	25.8	26.7	24.3	23.9	26.1	25.9	26.3
01:00-02:00	24.6	24.7	25.0	24.6	25.0	24.2	23.6	24.9	24.9	25.3	24.3	24.9	23.9	23.5	24.4	23.7	24.2	24.4	25.4	24.1	23.4	24.5	24.2	24.0	24.1	24.5	22.7	22.1	23.9	23.9	24.5
02:00-03:00	23.5	23.7	23.9	23.4	23.8	22.9	22.6	23.9	24.0	24.6	23.7	23.7	22.9	23.0	23.4	23.1	23.3	23.1	24.2	22.9	22.5	23.5	23.5	23.3	23.0	23.6	20.8	21.6	23.3	23.0	23.8
03:00-04:00	23.1	23.3	23.5	23.3	23.3	22.1	22.2	23.6	23.7	24.4	23.4	23.3	22.1	22.9	23.2	22.7	23.0	22.4	23.6	22.0	22.1	23.3	23.5	23.1	23.1	23.2	20.4	0.0	23.0	22.8	23.7
04:00-05:00	23.0	23.1	23.7	22.9	23.1	22.1	22.2	23.6	23.5	24.5	23.4	23.1	22.1	22.8	23.2	22.7	22.9	22.8	23.3	22.0	22.0	23.2	23.4	23.0	23.0	23.1	20.7	21.1	22.9	22.8	23.7
05:00-06:00	23.2	23.5	23.7	23.3	23.5	22.3	22.4	23.9	24.0	24.6	23.6	23.3	22.4	22.8	23.4	22.8	23.3	23.0	23.6	21.8	22.3	23.3	23.6	23.1	23.0	23.3	20.7	21.4	23.2	23.2	23.9
06:00-07:00	23.9	24.2	24.4	23.9	23.8	22.2	23.3	24.5	24.5	25.1	23.8	23.6	22.2	23.4	23.8	23.3	23.7	23.4	23.5	21.4	22.7	23.7	24.0	23.5	23.3	23.2	20.3	21.6	23.7	23.5	24.1
07:00-08:00	25.4	25.6	26.1	25.5	24.7	22.2	25.4	26.4	26.5	26.6	25.4	24.6	22.3	25.2	25.4	24.7	25.2	25.4	24.6	21.4	24.6	25.4	25.1	25.2	25.2	24.4	20.5	23.6	25.5	25.1	25.6
08:00-09:00	29.3	29.7	30.1	29.6	28.1	23.4	29.9	30.6	30.9	30.5	29.8	27.8	23.2	29.0	29.2	28.7	29.1	29.6	27.9	23.1	29.2	29.4	29.1	29.7	29.9	27.6	22.0	28.4	30.0	29.3	29.8
09:00-10:00	31.9	32.4	32.7	32.6	31.5	25.6	33.2	33.7	33.6	33.3	32.1	30.5	25.4	32.3	31.9	31.6	31.7	32.2	30.9	25.1	32.1	32.0	31.8	32.0	32.3	30.5	23.9	31.1	32.7	31.7	31.7
10:00-11:00	32.8	33.3	33.6	33.3	32.8	27.0	34.4	34.5	34.5	34.2	33.2	31.5	26.5	33.3	33.0	32.4	32.3	32.9	31.8	26.4	32.9	32.7	32.4	32.6	32.9	31.4	25.6	32.1	33.3	32.3	32.6
11:00-12:00	33.2	33.7	34.0	33.4	33.4	27.9	35.0	34.8	34.8	34.5	33.4	32.0	27.0	33.7	33.3	32.7	32.4	32.6	32.1	27.2	33.0	32.7	32.3	32.6	33.0	31.6	26.2	32.3	33.3	32.5	32.9
12:00-13:00	32.2	32.5	32.8	32.0	32.2	27.7	33.5	33.2	33.2	32.5	31.2	30.9	26.9	32.1	31.6	31.3	30.7	30.1	30.6	26.6	31.4	31.0	30.8	31.0	30.9	30.5	25.7	30.9	31.6	30.7	31.2
13:00-14:00	32.3	32.7	32.4	32.1	32.0	27.5	33.4	33.3	33.3	32.6	31.6	30.6	26.9	32.3	31.7	31.3	30.6	30.6	30.3	26.4	31.4	31.0	30.8	31.2	31.4	30.2	25.6	30.8	31.5	30.7	31.2
14:00-15:00	32.6	32.9	32.6	32.3	31.5	27.3	33.9	33.7	33.7	32.8	31.9	30.2	26.8	32.5	31.8	31.6	30.8	30.9	30.2	25.8	31.5	31.3	31.2	31.4	31.9	29.7	25.4	30.8	31.7	31.2	31.3
15:00-16:00	32.4	32.6	32.2	32.2	31.0	27.2	33.6	33.5	33.4	32.6	31.6	29.7	26.6	32.2	31.5	31.4	30.6	30.7	29.6	25.4	31.3	31.1	30.9	31.3	31.2	28.9	25.0	30.6	31.3	30.9	30.9
16:00-17:00	32.6	32.9	32.6	32.5	31.0	27.5	33.7	33.8	33.7	32.8	32.1	29.4	27.0	32.3	31.8	31.5	30.7	30.7	29.4	25.7	31.3	31.1	30.8	31.3	31.2	28.6	24.7	30.8	31.4	30.8	30.9
17:00-18:00	33.0	33.5	32.6	33.0	31.2	28.5	34.3	34.3	34.1	33.4	32.6	29.9	27.5	32.9	32.2	31.9	31.3	31.5	29.9	27.1	31.6	31.3	31.0	31.6	31.6	29.0	25.9	31.0	31.2	30.8	30.7
18:00-19:00	33.2	33.7	33.1	33.4	32.2	30.1	34.5	34.5	34.5	34.1	33.2	31.4	29.2	33.3	32.8	32.5	32.4	32.7	31.5	29.4	32.8	32.5	32.7	32.7	32.7	30.7	27.9	31.5	31.7	30.9	30.9
19:00-20:00	32.9	32.8	32.7	32.5	31.7	30.1	33.9	33.8	33.0	33.0	32.0	30.9	29.2	32.5	32.2	32.1	32.0	32.4	31.5	29.5	32.3	32.5	32.2	32.4	32.1	31.0	28.4	31.6	32.3	31.7	31.7
20:00-21:00	32.1	32.1	31.8	32.1	31.1	29.6	33.2	33.0	32.4	32.3	31.5	30.3	28.9	31.8	31.5	31.6	31.5	31.9	30.9	29.1	31.9	31.9	31.4	31.7	31.4	30.4	28.1	31.6	32.0	31.9	31.9
21:00-22:00	31.7	31.5	31.2	31.6	30.6	29.2	33.2	32.3	31.8	31.9	30.8	30.1	28.7	31.2	31.2	31.1	30.8	31.6	30.8	29.1	31.4	31.3	30.6	31.1	30.9	29.9	28.1	30.7	31.3	31.0	31.2
22:00-23:00	31.0	31.1	30.9	31.5	30.2	28.9	32.3	31.9	31.3	31.3	30.5	29.4	28.3	30.9	30.7	30.6	30.6	31.0	30.2	28.6	31.0	30.8	30.3	30.6	30.5	29.5	27.6	30.2	31.0	30.7	30.7
23:00-24:00	29.7	30.0	30.0	30.5	29.3	27.9	31.0	30.7	30.3	30.2	29.4	28.5	27.4	29.6	29.6	29.5	29.4	29.7	29.1	27.4	29.8	29.7	29.1	29.6	29.5	28.6	26.6	29.0	29.8	29.7	29.9

Table A1.2 Capacities in MW for average historical day

Hours	Working day	Saturday	Sunday+holidays
00:00-01:00	26.1	27.0	25.4
01:00-02:00	24.2	25.0	23.7
02:00-03:00	23.3	23.8	22.3
03:00-04:00	22.1	23.4	21.6
04:00-05:00	23.0	23.2	21.7
05:00-06:00	23.2	23.4	21.8
06:00-07:00	23.7	23.5	21.6
07:00-08:00	25.4	24.6	21.6
08:00-09:00	29.6	27.9	22.9
09:00-10:00	32.3	30.8	25.0
10:00-11:00	33.1	31.9	26.4
11:00-12:00	33.3	32.3	27.1
12:00-13:00	31.7	31.0	26.7
13:00-14:00	31.8	30.8	26.6
14:00-15:00	32.0	30.4	26.3
15:00-16:00	31.7	29.8	26.1
16:00-17:00	31.9	29.6	26.2
17:00-18:00	32.2	30.0	27.3
18:00-19:00	32.9	31.5	29.1
19:00-20:00	32.5	31.3	29.3
20:00-21:00	31.9	30.7	28.9

le A1.3 Weighted coefficients in p.u. for average historical days

Hours	Working day	Saturday	Sunday+holidays
00:00-01:00	0.0373	0.0396	0.0415
01:00-02:00	0.0346	0.0367	0.0388
02:00-03:00	0.0333	0.0350	0.0365
03:00-04:00	0.0316	0.0343	0.0353
04:00-05:00	0.0329	0.0340	0.0355
05:00-06:00	0.0332	0.0344	0.0356
06:00-07:00	0.0339	0.0346	0.0352
07:00-08:00	0.0363	0.0361	0.0353
08:00-09:00	0.0423	0.0409	0.0375
09:00-10:00	0.0461	0.0453	0.0408
10:00-11:00	0.0473	0.0468	0.0431
11:00-12:00	0.0476	0.0475	0.0443
12:00-13:00	0.0452	0.0456	0.0437
13:00-14:00	0.0454	0.0452	0.0434
14:00-15:00	0.0457	0.0446	0.0430
15:00-16:00	0.0453	0.0438	0.0426
16:00-17:00	0.0455	0.0435	0.0429
17:00-18:00	0.0460	0.0441	0.0445
18:00-19:00	0.0470	0.0462	0.0476
19:00-20:00	0.0464	0.0460	0.0478
20:00-21:00	0.0456	0.0451	0.0473

Table A1.4. Values K_h*10^2 for planning month

s	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31
	Tue	Fri	Sat	Su	Mon	T	W	Tue	Fri	Sat	Su	Mon	T	W	Tue	Fri	Sat	Su	Mon	T	W	Tue	Fri	Sat	Su	Mon	T	W	Tue	Fri	Sat
00:00-01:00	3.73	3.73	3.85	3.63	3.76	3.76	3.76	3.76	3.76	3.88	3.76	3.68	3.68	3.68	3.68	3.68	3.80	3.58	3.62	3.62	3.62	3.62	3.62	3.74	3.53	3.66	3.66	3.66	3.66	3.66	3.79
01:00-02:00	3.46	3.46	3.57	3.39	3.49	3.49	3.49	3.49	3.49	3.59	3.50	3.41	3.41	3.41	3.41	3.41	3.52	3.35	3.36	3.36	3.36	3.36	3.36	3.47	3.30	3.40	3.40	3.40	3.40	3.40	3.51
02:00-03:00	3.33	3.33	3.40	3.19	3.36	3.36	3.36	3.36	3.36	3.43	3.36	3.29	3.29	3.29	3.29	3.29	3.36	3.15	3.24	3.24	3.24	3.24	3.24	3.31	3.10	3.28	3.28	3.28	3.28	3.28	3.35
03:00-04:00	3.16	3.16	3.34	3.09	3.19	3.19	3.19	3.19	3.19	3.36	3.32	3.12	3.12	3.12	3.12	3.12	3.29	3.05	3.07	3.07	3.07	3.07	3.07	3.24	3.00	3.11	3.11	3.11	3.11	3.11	3.28
04:00-05:00	3.29	3.29	3.31	3.10	3.31	3.31	3.31	3.31	3.31	3.33	3.31	3.25	3.25	3.25	3.25	3.25	3.27	3.07	3.20	3.20	3.20	3.20	3.20	3.22	3.02	3.23	3.23	3.23	3.23	3.23	3.25
05:00-06:00	3.32	3.32	3.35	3.11	3.35	3.35	3.35	3.35	3.35	3.38	3.34	3.28	3.28	3.28	3.28	3.28	3.31	3.07	3.23	3.23	3.23	3.23	3.23	3.26	3.02	3.26	3.26	3.26	3.26	3.26	3.29
06:00-07:00	3.39	3.39	3.36	3.08	3.42	3.42	3.42	3.42	3.42	3.39	3.43	3.35	3.35	3.35	3.35	3.35	3.32	3.04	3.29	3.29	3.29	3.29	3.29	3.27	2.99	3.33	3.33	3.33	3.33	3.33	3.30
07:00-08:00	3.63	3.63	3.51	3.08	3.66	3.66	3.66	3.66	3.66	3.54	3.67	3.58	3.58	3.58	3.58	3.58	3.47	3.04	3.53	3.53	3.53	3.53	3.53	3.41	3.00	3.57	3.57	3.57	3.57	3.57	3.45
08:00-09:00	4.23	4.23	3.98	3.27	4.26	4.26	4.26	4.26	4.26	4.01	4.26	4.17	4.17	4.17	4.17	4.17	3.93	3.23	4.11	4.11	4.11	4.11	4.11	3.87	3.18	4.16	4.16	4.16	4.16	4.16	3.91
09:00-10:00	4.61	4.61	4.41	3.57	4.65	4.65	4.65	4.65	4.65	4.44	4.66	4.55	4.55	4.55	4.55	4.55	4.35	3.52	4.48	4.48	4.48	4.48	4.48	4.28	3.47	4.53	4.53	4.53	4.53	4.53	4.33
10:00-11:00	4.73	4.73	4.55	3.77	4.77	4.77	4.77	4.77	4.77	4.59	4.79	4.67	4.67	4.67	4.67	4.67	4.49	3.72	4.60	4.60	4.60	4.60	4.60	4.42	3.66	4.65	4.65	4.65	4.65	4.65	4.47
11:00-12:00	4.76	4.76	4.62	3.87	4.80	4.80	4.80	4.80	4.80	4.65	4.83	4.70	4.70	4.70	4.70	4.70	4.56	3.82	4.62	4.62	4.62	4.62	4.62	4.49	3.76	4.68	4.68	4.68	4.68	4.68	4.54
12:00-13:00	4.52	4.52	4.43	3.82	4.56	4.56	4.56	4.56	4.56	4.47	4.62	4.47	4.47	4.47	4.47	4.47	4.38	3.77	4.40	4.40	4.40	4.40	4.40	4.31	3.71	4.45	4.45	4.45	4.45	4.45	4.36
13:00-14:00	4.54	4.54	4.39	3.80	4.57	4.57	4.57	4.57	4.57	4.43	4.63	4.48	4.48	4.48	4.48	4.48	4.34	3.75	4.41	4.41	4.41	4.41	4.41	4.27	3.69	4.46	4.46	4.46	4.46	4.46	4.32
14:00-15:00	4.57	4.57	4.34	3.76	4.61	4.61	4.61	4.61	4.61	4.37	4.67	4.52	4.52	4.52	4.52	4.52	4.28	3.71	4.45	4.45	4.45	4.45	4.45	4.22	3.65	4.50	4.50	4.50	4.50	4.50	4.27
15:00-16:00	4.53	4.53	4.26	3.72	4.57	4.57	4.57	4.57	4.57	4.29	4.63	4.48	4.48	4.48	4.48	4.48	4.21	3.68	4.41	4.41	4.41	4.41	4.41	4.14	3.62	4.46	4.46	4.46	4.46	4.46	4.19
16:00-17:00	4.55	4.55	4.23	3.75	4.59	4.59	4.59	4.59	4.59	4.26	4.68	4.50	4.50	4.50	4.50	4.50	4.17	3.70	4.43	4.43	4.43	4.43	4.43	4.11	3.64	4.48	4.48	4.48	4.48	4.48	4.16
17:00-18:00	4.60	4.60	4.28	3.89	4.64	4.64	4.64	4.64	4.64	4.32	4.74	4.55	4.55	4.55	4.55	4.55	4.23	3.84	4.48	4.48	4.48	4.48	4.48	4.17	3.78	4.53	4.53	4.53	4.53	4.53	4.21
18:00-19:00	4.70	4.70	4.49	4.16	4.74	4.74	4.74	4.74	4.74	4.53	4.79	4.64	4.64	4.64	4.64	4.64	4.44	4.11	4.57	4.57	4.57	4.57	4.57	4.37	4.05	4.62	4.62	4.62	4.62	4.62	4.42
19:00-20:00	4.64	4.64	4.47	4.18	4.68	4.68	4.68	4.68	4.68	4.51	4.67	4.58	4.58	4.58	4.58	4.58	4.41	4.13	4.51	4.51	4.51	4.51	4.51	4.35	4.07	4.56	4.56	4.56	4.56	4.56	4.39
20:00-21:00	4.56	4.56	4.38	4.13	4.60	4.60	4.60	4.60	4.60	4.42	4.58	4.50	4.50	4.50	4.50	4.50	4.33	4.08	4.43	4.43	4.43	4.43	4.43	4.26	4.02	4.48	4.48	4.48	4.48	4.48	4.31
21:00-22:00	4.48	4.48	4.33	4.11	4.52	4.52	4.52	4.52	4.52	4.37	4.51	4.43	4.43	4.43	4.43	4.43	4.28	4.06	4.36	4.36	4.36	4.36	4.36	4.21	3.99	4.41	4.41	4.41	4.41	4.41	4.26
22:00-23:00	4.42	4.42	4.26	4.05	4.46	4.46	4.46	4.46	4.46	4.30	4.44	4.36	4.36	4.36	4.36	4.36	4.21	4.00	4.30	4.30	4.30	4.30	4.30	4.14	3.94	4.34	4.34	4.34	4.34	4.34	4.19
23:00-24:00	4.26	4.26	4.13	3.90	4.29	4.29	4.29	4.29	4.29	4.16	4.28	4.21	4.21	4.21	4.21	4.21	4.07	3.86	4.14	4.14	4.14	4.14	4.14	4.01	3.80	4.19	4.19	4.19	4.19	4.19	4.06

Table A1.5 Capacities for planning month in MW

Days	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31
	Tue	Fri	Sat	Su	Mon	T	W	Tue	Fri	Sat	Su	Mon	T	W	Tue	Fri	Sat	Su	Mon	T	W	Tue	Fri	Sat	Su	Mon	T	W	Tue	Fri	Sat
00:00-01:00	27.2	27.2	28.1	26.4	27.4	27.4	27.4	27.4	27.4	28.3	27.4	26.8	26.8	26.8	26.8	26.8	27.7	26.1	26.4	26.4	26.4	26.4	26.4	27.3	25.7	26.7	26.7	26.7	26.7	26.7	27.6
01:00-02:00	25.2	25.2	26.0	24.7	25.4	25.4	25.4	25.4	25.4	26.2	25.5	24.9	24.9	24.9	24.9	24.9	25.7	24.4	24.5	24.5	24.5	24.5	24.5	25.3	24.0	24.8	24.8	24.8	24.8	24.8	25.6
02:00-03:00	24.3	24.3	24.8	23.3	24.5	24.5	24.5	24.5	24.5	25.0	24.5	24.0	24.0	24.0	24.0	24.0	24.5	23.0	23.6	23.6	23.6	23.6	23.6	24.1	22.6	23.9	23.9	23.9	23.9	23.9	24.4
03:00-04:00	23.1	23.1	24.3	22.5	23.3	23.3	23.3	23.3	23.3	24.5	24.2	22.8	22.8	22.8	22.8	22.8	24.0	22.2	22.4	22.4	22.4	22.4	22.4	23.6	21.9	22.7	22.7	22.7	22.7	22.7	23.9
04:00-05:00	24.0	24.0	24.1	22.6	24.2	24.2	24.2	24.2	24.2	24.3	24.1	23.7	23.7	23.7	23.7	23.7	23.8	22.4	23.3	23.3	23.3	23.3	23.3	23.4	22.0	23.6	23.6	23.6	23.6	23.6	23.7
05:00-06:00	24.2	24.2	24.4	22.7	24.4	24.4	24.4	24.4	24.4	24.6	24.4	23.9	23.9	23.9	23.9	23.9	24.1	22.4	23.5	23.5	23.5	23.5	23.5	23.7	22.1	23.8	23.8	23.8	23.8	23.8	24.0
06:00-07:00	24.7	24.7	24.5	22.4	24.9	24.9	24.9	24.9	24.9	24.7	25.0	24.4	24.4	24.4	24.4	24.4	24.2	22.2	24.0	24.0	24.0	24.0	24.0	23.8	21.8	24.3	24.3	24.3	24.3	24.3	24.1
07:00-08:00	26.4	26.4	25.6	22.5	26.7	26.7	26.7	26.7	26.7	25.8	26.8	26.1	26.1	26.1	26.1	26.1	25.3	22.2	25.7	25.7	25.7	25.7	25.7	24.9	21.9	26.0	26.0	26.0	26.0	26.0	25.2
08:00-09:00	30.8	30.8	29.0	23.9	31.1	31.1	31.1	31.1	31.1	29.3	31.1	30.4	30.4	30.4	30.4	30.4	28.7	23.6	30.0	30.0	30.0	30.0	30.0	28.2	23.2	30.3	30.3	30.3	30.3	30.3	28.5
09:00-10:00	33.6	33.6	32.1	26.0	33.9	33.9	33.9	33.9	33.9	32.4	33.9	33.2	33.2	33.2	33.2	33.2	31.7	25.7	32.7	32.7	32.7	32.7	32.7	31.2	25.3	33.1	33.1	33.1	33.1	33.1	31.6
10:00-11:00	34.5	34.5	33.2	27.5	34.8	34.8	34.8	34.8	34.8	33.5	34.9	34.1	34.1	34.1	34.1	34.1	32.8	27.1	33.5	33.5	33.5	33.5	33.5	32.3	26.7	33.9	33.9	33.9	33.9	33.9	32.6
11:00-12:00	34.7	34.7	33.6	28.2	35.0	35.0	35.0	35.0	35.0	33.9	35.2	34.3	34.3	34.3	34.3	34.3	33.2	27.9	33.7	33.7	33.7	33.7	33.7	32.7	27.4	34.1	34.1	34.1	34.1	34.1	33.1
12:00-13:00	33.0	33.0	32.3	27.8	33.3	33.3	33.3	33.3	33.3	32.6	33.7	32.6	32.6	32.6	32.6	32.6	31.9	27.5	32.1	32.1	32.1	32.1	32.1	31.4	27.1	32.4	32.4	32.4	32.4	32.4	31.8
13:00-14:00	33.1	33.1	32.0	27.7	33.3	33.3	33.3	33.3	33.3	32.3	33.7	32.7	32.7	32.7	32.7	32.7	31.6	27.4	32.1	32.1	32.1	32.1	32.1	31.1	26.9	32.5	32.5	32.5	32.5	32.5	31.5
14:00-15:00	33.3	33.3	31.6	27.4	33.6	33.6	33.6	33.6	33.6	31.9	34.1	32.9	32.9	32.9	32.9	32.9	31.2	27.1	32.4	32.4	32.4	32.4	32.4	30.8	26.6	32.8	32.8	32.8	32.8	32.8	31.1
15:00-16:00	33.0	33.0	31.0	27.1	33.3	33.3	33.3	33.3	33.3	31.3	33.8	32.6	32.6	32.6	32.6	32.6	30.7	26.8	32.1	32.1	32.1	32.1	32.1	30.2	26.4	32.5	32.5	32.5	32.5	32.5	30.5
16:00-17:00	33.2	33.2	30.8	27.3	33.5	33.5	33.5	33.5	33.5	31.1	34.1	32.8	32.8	32.8	32.8	32.8	30.4	27.0	32.3	32.3	32.3	32.3	32.3	30.0	26.6	32.6	32.6	32.6	32.6	32.6	30.3
17:00-18:00	33.6	33.6	31.2	28.4	33.8	33.8	33.8	33.8	33.8	31.5	34.6	33.2	33.2	33.2	33.2	33.2	30.8	28.0	32.6	32.6	32.6	32.6	32.6	30.4	27.6	33.0	33.0	33.0	33.0	33.0	30.7
18:00-19:00	34.2	34.2	32.8	30.3	34.5	34.5	34.5	34.5	34.5	33.0	34.9	33.8	33.8	33.8	33.8	33.8	32.4	30.0	33.3	33.3	33.3	33.3	33.3	31.9	29.5	33.7	33.7	33.7	33.7	33.7	32.2
19:00-20:00	33.8	33.8	32.6	30.5	34.1	34.1	34.1	34.1	34.1	32.9	34.1	33.4	33.4	33.4	33.4	33.4	32.2	30.1	32.9	32.9	32.9	32.9	32.9	31.7	29.6	33.2	33.2	33.2	33.2	33.2	32.0
20:00-21:00	33.3	33.3	31.9	30.1	33.5	33.5	33.5	33.5	33.5	32.2	33.4	32.8	32.8	32.8	32.8	32.8	31.6	29.8	32.3	32.3	32.3	32.3	32.3	31.1	29.3	32.7	32.7	32.7	32.7	32.7	31.4
21:00-22:00	32.7	32.7	31.6	30.0	32.9	32.9	32.9	32.9	32.9	31.9	32.9	32.3	32.3	32.3	32.3	32.3	31.2	29.6	31.8	31.8	31.8	31.8	31.8	30.7	29.1	32.1	32.1	32.1	32.1	32.1	31.1
22:00-23:00	32.2	32.2	31.1	29.5	32.5	32.5	32.5	32.5	32.5	31.3	32.4	31.8	31.8	31.8	31.8	31.8	30.7	29.2	31.3	31.3	31.3	31.3	31.3	30.2	28.7	31.7	31.7	31.7	31.7	31.7	30.6
23:00-24:00	31.1	31.1	30.1	28.5	31.3	31.3	31.3	31.3	31.3	30.3	31.2	30.7	30.7	30.7	30.7	30.7	29.7	28.1	30.2	30.2	30.2	30.2	30.2	29.2	27.7	30.5	30.5	30.5	30.5	30.5	29.6

Annex 2

Electricity Losses Allocation on Georgian Electricity arket

A2.1. Background

The new model of the Georgian electricity market implies a transition to hourly settlements and will initially (Phase 1) operate on model of bilateral contracts and a balancing mechanism.

Bilateral contracts should be concluded at least for one month duration and based on Month Ahead Planning (MAP) concept (see Part 1 of this report).

It should be noted that the responsibility borders of ompetitive market participants in Georgia may be the connection points to either transmi on or distribution networks.

Thus, in this report, the electricity losses will be understood exactly as losses in the network for the competitive electricity market, rather than the losses in the transmission or distribution networks. On ESCO's website these loss are defined as transportation expenses.

Here we will use the term competitive market losses or losses. The task lies in th fair allocation of these losses.

The approach to fair losses allocation should be guided both by technical and price aspects that requires the need for a comprehensive approach.

First consider physical approach for determining losses on the market, the c tribution of each consumer in losses creation and the portion of each generator in their coverage.

A2.2. Physical method for losses allocation and struct ral analysis.

For each hour of a planned month based on MAP data, the load flow calculations will be performed by GSE using PSS/E software.

In Fig.A2.1 the results of calculations for a hypothet 5-node system for one hour are presented.

After load flow calculation by special mechanisms[1,2] the following parameters are defined (Table A2.1):

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[1]V. Safaryan. "Structural Analysis of Power Flows and L sses in Electrical Circuits". Proceedings of the Academy of Sciences of Republic of Armenia, TN 2001,

[2]V. Safaryan. "Analysis of Directions of Flows of Active Capacity of Electric Circuits". CJSC "Institute of Energy". Yerevan, 2001-8p

P_{ij} -consumption portion of jth consumer from ith generator,

ΔP_{ij} -active capacity losses due to P_{ij},

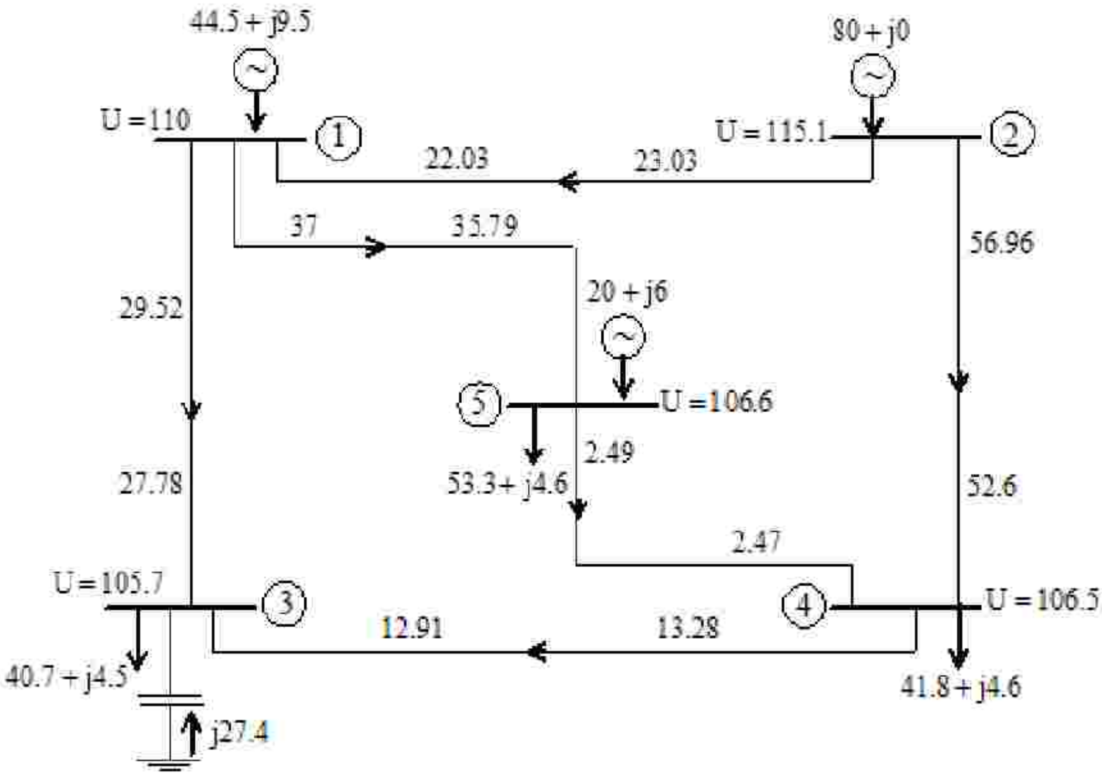
$P_{ij} + \Delta P_{ij}$ -generation portion of ith plant to jth consumer,

$\Delta P_i = \sum_j \Delta P_{ij}$ -losses covered by ith generator,

$\Delta P_j = \sum_i \Delta P_{ij}$ -losses created by jth consumer,

$\Delta P = \sum_i \Delta P_i = \sum_j \Delta P_j$ -losses in network.

Fig.A2.1. Load flow calculations results (Option 1)



The following conditions are satisfied

$P_i = \sum_j (P_{ij} + \Delta P_{ij})$ -active capacity of ith generator,

$P_j = \sum_i P_{ij}$ -active capacity of jth consumer,

$$\sum_i P_i = \sum_j P_j + \Delta P$$ - active capacity balance.

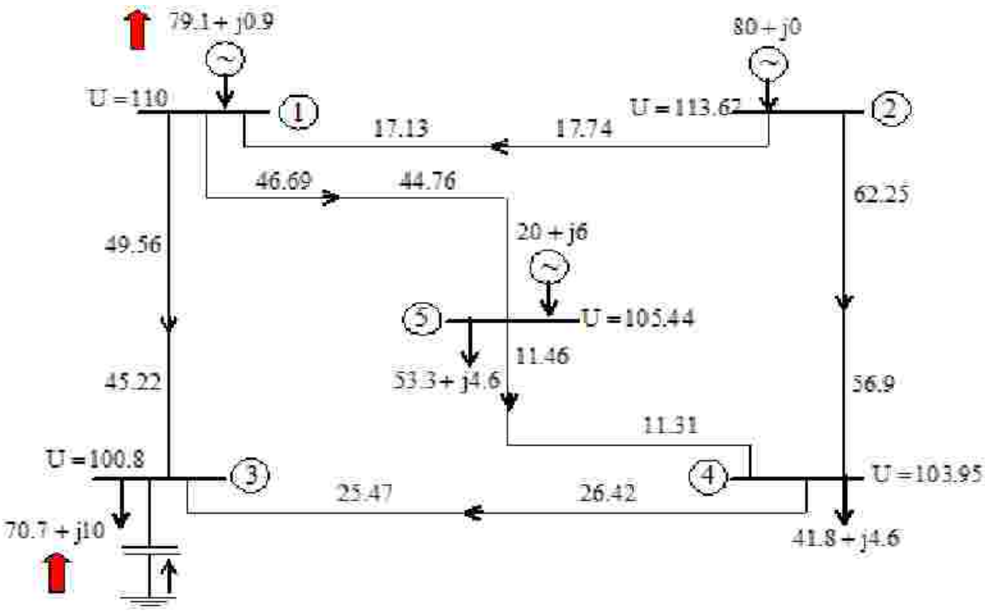
Table A2.1 Structural analysis results (Option 1)

			Consumers			Losses covered by generators
			bus3	bus4	bus5	
			40.7	**41.8**	**53.3**	
Generators	bus1	**44.501**	18.835	0.806	22.869	**1.991**
	bus2	**80**	21.657	40.321	11.323	**6.699**
	bus5	**20**	0.208	0.673	19.108	**0.011**
	Losses created by consumers		**3.628**	**3.380**	**1.694**	**8.701**

A2.3. Disadvantages to use physical method for fair allocati n of market losses in Georgia

1. As can be seen from the Table A2.1,the structure of th grid has a great impact on the losses created. So although the Load 5 is the biggest, it creates fewer losses due to proximity to Generator 5 despite the fact that its c y is small. At the same time the Generator 5 does not take part in covering system losses.
2. The influence of one wholesale consumer on others also is a disadvantage. This is seen from the results shown on Fig. A2.2. The difference with above regime is the load increasing in Node 3 only (generation in Node 1 is increased too).

Fig.A2.2. Load flow calculations results (Option 2)



As seen from Table A2.2,the portions of losses created by all consumers are increasing.

Table A2.2 Structural analysis results (Option 1)

			Consumers			Losses covered by generators
			bus3	bus4	bus5	
			70.7	41.8	53.3	
Generators	bus1	79.1	39.57	3.93	30.28	5.32
	bus2	80	29.82	35.72	6.56	7.9
	bus5	20	1.3	2.14	16.46	0.1
Losses created by consumers			7.89	3.6	1.83	13.32

What does this mean in terms of the competitive market?

Suppose that a competitive electricity market participant operates on the market in accordance with the planned indicators and pays its portion of the losses calculated in accordance with the planned dispatch reg e on the market. Another participant whose actual deliveries or receipt from the market deviates from the planned dispatch regime, results in a change of losses. In compliance with the principle of fairness, only this participant ld be responsible for the loss deviation (by the physical method that would not happen).

3. As seen from Tables A2.1 and A2.2, there is a different mix of generators in covering losses. Therefore the price of losses is different too for these regimes. With load increasing, it's possible this price growth aking into account the involvement in the balance less efficient generators o ore import.

4. In accordance with MAP (DAP) concept it's necessary initially o determine value Net generation minus Losses for each generator to conclude bilateral contracts. If you make calculations at the end of the month the losses covered by the generator can be different in comparison with planned regimes.

A2.4. Proposed mechanism for losses allocation for Georgian electricity market

The description below is the essence of the proposed approach in relation to the Phase 1 (GEMM 2015) of the reform of the Georgian electricity market, namely the operation on the basis of bilateral contracts and hourly balancing mechanism.

Note that in the future when implementing Day Ahead Market (DAM) two types of deviations (for the DAM and the balancing market) will be calculated with a decrease in portion through bilateral contracts.

Proposed mechanism consists of two steps:

- Ø Loss allocation for planned regimes for coming month based on MAP shapes;
- Ø Additional losses allocation due to deviations and market participants responsibility at the end of the month based on actual regime analysis.

All of the below-mentioned considerations are given for one hour.

Not to complicate the text, let's imagine that the above mentioned Option 1 afterwards will regard to planned regime and the Option 2 is for the actual one.

Step 1 Planning losses for coming month allocation by hours

1. Hourly losses calculation for competitive electricity market based on Month Ahead Planning shapes;

2. Calculation of losses covered by each generator based n structural analysis (physical method) - ?P_i (see paragraph A2.2);

3. Volume of losses to be paid by each consumer (domestic trader, etc.) determination in proportion of consumption (see Table 4.3).

$$\Delta C_j = \frac{\sum_i \Delta P_i}{\sum_j C_j} * C_j$$

Proposed approach removes disadvantages 1 (historical ructure of the Georgian power system), 3 (possible different losses price for onsumers),4 (the need to taking into account losses in advance) and partially 2 (consumption of one consum impact to others) mentioned in paragraph A2.3.

Table A2.3 Losses allocation by physical and proposed methods for Option 1 in MWh

	Bus 3	Bus 4	Bus 5
Physical method	3.628	3.380	1.694
Proposed (step 1)	2.607	2.678	3.415

For using the proposed approach the calculations of ho y planning regimes (reactive power of load must be estimate too) are required.

To avoid these calculations (if any difficulties occur) it's possible to use simplified approach, namely, taking into account loss allocation proportion with consumption, it's possible to use average percentage for system losses for each c nsumer based on historical data (Table A2.4).

Table A2.4 Historical calculated losses (transportation expenses) on Georgian electricity market in % (ESCO's data)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Year
2010	1.85	1.59	1.58	1.56	1.60	1.90	1.69	2.12	1.87	1.74	1.60	1.64	***1.73***
2011	2.13	2.22	1.61	1.68	1.61	1.84	1.88	2.17	1.95	1.68	2.11	1.74	***1.89***
2012	1.70	1.87	1.93	1.67	1.83	1.74	1.86	1.78	1.59	1.75	1.81	1.72	***1.77***

For this approach the following formula can be used

$$\Delta Cj = Losses\ \%/100 * \sum_i Pi * \frac{Cj}{\sum_j Cj}$$

where P_i – net generation of i^{th} generator based on MAP (DAP),

C_j – consumption of j^{th} wholesale consumer based on MAP (DAP),

Losses% - average competitive market losses level in %.

This approach doesn't require hourly preliminary load flow calculati ns, but the hourly detailed analysis of historical regimes is needed.

Both options of proposed mechanism can be implemented for planning regime only.

Step 2 Additional losses allocation due to actual and planning regimes deviations

Step 2 is provided because the deviations between actual and planning regimes of participants are unavoidable.

1. At the end of the month, the TSO carries out the calculation of hourly losses based on actual regime and according to the method of structural analysis determines the values of the losses created by each consumer and covered by each generator (physical method).

2. Deviation of each consumer is determined as

$$D_j = A_j - C_j$$

3. Difference in losses between actual and planning regim (A, G – actual and planned consumption and generation correspondingly)

$$D_{losses} = \sum_i (G_i - P_i) - \sum_j (A_j - C_j)$$

4. Finally the losses to be paid by each consumer are cal ted based on Step 1 and additional losses allocation in proportion with pa ticipant's deviations

$$L_j = \Delta C_j + D_{losses} * D_j / \sum_j D_j$$

For above example, the final losses allocation is presented in Table A2.5.

Table A2.5 Proposed losses allocation for above example in MWh

	Bus 3	Bus 4	Bus 5
Physical method for actual regime	7.89	3.60	1.83
Physical method for planned regime	3.63	3.38	1.69
Deviations by physical method	4.26	0.22	0.14
Losses for planned regime by proposed method	2.61	2.68	3.42
Deviations by proposed method	4.62	0	0
Losses to be paid	7.23	2.68	3.42

USAID Hydropower Investment Promotion Project (USAID-HIPP)

Deloitte Consulting Overseas Projects - HIPP

13th floor, 11, Apakidze str, Tiflis Business Center,

Tbilisi, 0171, Georgia