A Cost-Based Approach to Elicit Ancillary Service Tariffs from Unified Capacity and Energy Tariffs

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Abstract—**Establishing separated markets for capacity, energy, and ancillary services (AS) is one of the key steps to liberalize electricity sector and realize electricity markets. This study aims at eliciting AS tariffs from unified capacity and energy tariffs through a cost-based approach. In the proposed framework, maintaining annual revenue requirements of the power plants is considered as the main objective while separating the AS tariff from unified tariffs. The conducted study considers two types of unified tariffs, i.e., capacity and energy tariffs, and offers proper AS eliciting scheme for each type of unified tariffs. The main challenges addressed here are: 1) incentivizing\penalizing AS provision more\less than scheduled amount which is tackled through an incentive factor, and 2) preventing overall tariff increment (customer tariff) after eliciting AS tariff which is addressed by applying fixing constraint to the overall tariff at before and after AS tariff eliciting conditions. Last but not the least, AS trade between adjacent utilities and calculating the benefits from this trade are addressed. The effectiveness of the proposed methodology is assured through numerical investigations.**

Index Terms—**Ancillary Service, Balancing Market, Frequency Regulation, Capacity Tariff, Energy Tariff.**

I. INTRODUCTION

ANCILLARY SERVICES and balancing facilities are countermeasures to ensure nodal power balances when

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the system operation parameters are violated from pre-scheduled condition [1]-[3]. Day-ahead scheduling and market clearance identify the committed generation units, determine associated operating points and allocate required reserves for the next operating day. Meanwhile, power system operator must ensure that sufficient resources are available, given any variation in system operation conditions from the day-ahead schedules, and power plants are dispatched on a moment-to-moment basis maintaining system balance and security [4]-[6].

To maintain the generation\consumption balance, the power system operator needs the ability of calling on identified generation assets or demand-side assets. AS is the service offered or facilitated by the power system operators for power quality procurement and system balancing purposes which allows multiple users to utilize the transmission network while preserving system security. The power system operators keep on hand to meet unexpected imbalances between pre-scheduled and actual load and generation. Balancing energy is the actual deployment of this capacity realized through set-aside reserve capacity which might be procured from market participants or neighbouring systems [7]. In other words, balancing services means either or both balancing capacity and balancing energy.

The language used to describe ancillary service, balancing facilities and imbalance notions is not always consistent across localities. One of the important aspects of the European Union (EU) Internal Energy Market (IEM) is to harmonize network operating practices, including how to define ancillary service and balancing facilities and imbalance notions [8]. "Balancing" is a process, while AS are diverse products to be defined and supplied for balancing. Balancing and AS are often discussed together because they are core functions for secure operation of power system. Some AS are part of the balancing function itself and designed to ensure continuous balancing of the power system. Other AS, say voltage (or reactive power) regulation, black start, are necessary for grid operation and security, but not necessarily for the balancing process [9]. This study addresses balancing aspects of AS which focuses on active power (MW) regulation capability (ramp up/down) of power plants.

This study addresses separation of AS tariffs from uniform capacity and energy tariffs for vertically integrated utilities (VIU) which are starting electricity market liberations and implementing uniform tariffs for power plants. Georgia,

Armenia and Black Sea region countries are among the countries which are at transition from VIU to liberalized electricity markets. Unified tariffs are implemented in many utilities round-the-globe, particularly in developing countries, to cover annual revenue requirements (ARR) of the power plants [10]. Eliciting AS tariffs from unified tariffs is among the most important duties of energy market regulatory authorities in these VIU as a critical step towards liberalizing electricity market opening. By the separated AS tariffs in place, 1) the true cost levels of providing AS can be identified; 2) Obeying to/violating from the pre-scheduled AS can be remunerated/penalized; 3) AS trade between the adjacent utilities can be initiated. However, the discussed benefits are in challenge with concerns such as how to incentivise AS providers; and how to prevent overall tariff increment (customer tariff) after eliciting AS tariff (see Fig. 1).
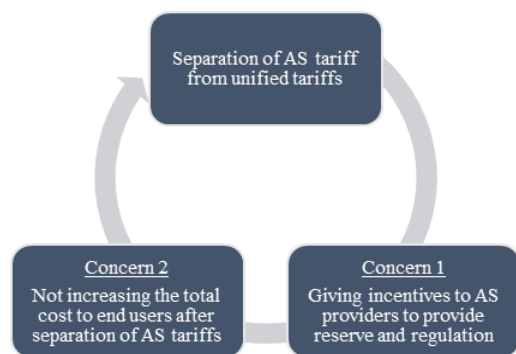

Fig.1. Concerns for separating AS tariffs from unified tariffs

Unified capacity tariffs (UCT) already include remuneration for providing AS independent from amount of AS provision. In other words, under unified tariff mechanisms, there is no motivation for the power plants to provide AS unless a penalty mechanism is introduced for the cases that the power plant refuse to provide AS. Under such a circumstance, the obvious solution is to separate the AS tariffs from the uniform tariffs and remunerate provision of AS through a separate AS tariffs mechanism. This is also required to calculate the benefits of utilities attained from coupling their ancillary service and balancing facilities services with other utilities through interconnection lines. Quantification of coupled AS provision, such as exchanging of spinning reserves between two countries, cannot be made properly unless AS tariff is separately calculated. Here, relevant studies in the literature are generally based on cost-based or market-based assumptions [11]. By separating AS tariff, those power plants who have enjoyed the remuneration of AS provision through unified tariffs will definitely be unwilling to adopt separated AS tariffs. The main reason is that such power plants will be remunerated - if and only if they provide AS satisfactorily. Therefore, an incentive mechanism should be considered in case of separated AS tariff methodology [12]. Nevertheless, such incentive mechanism should not result a significant increase in total payments to power plants as illustrated in Figure 1. Otherwise, it will be difficult for the energy market regulatory authorities to explain the tariff increment to the

end-users.

In a competitive AS market environment, price of AS provision is determined by the competition among the AS providers (referred as "market-based" approach) [13], [14]. Although it is aimed to procure AS through such market-based approaches, "cost-based" approaches are inevitable particularly at the initial phase of market opening [15]. In the cost-based approaches, price of a commodity is determined commonly based on either "marginal-based" or "pay-as-bid" mechanisms [16]. In "pay-as-bid" mechanisms, cost-based approaches should consider a profit component in determining ARRs of the power plants [17]. Profit component in pay-as-bid mechanisms is more critical than that of marginal-based mechanisms given that the market clearing at marginal price already provides a room for profit of power plants unless they are marginal.

Unified capacity and energy tariffs of power plants are generally determined annually using cost-based approaches [18]. Each year, power plants provide associated costs (fixed and variable) to energy market regulatory authorities. Afterwards, the ARRs for power plants are settled after some negotiations between the power plants and energy market regulatory authorities. ARRs are encompasses fixed costs (i.e., costs which are independent of power generation amount), variable costs (costs associated with power generation amount), depreciation costs, and profit component [19]. It is worth mentioning that cost-based approaches are also being utilized in developed markets when a market power/abuse is observed [18]. In such a case, energy market regulatory authorities identify the price based on cost-based approaches. Hence, separated AS tariffing is not an interim solution until market opening indeed and can be used in case of liberalized electricity market.

This paper offers a cost-based approach to elicit the AS tariffs from the unified tariffs. In the proposed framework, maintaining annual revenue requirements of the power plants are considered as the main objective while separating the AS tariff from unified tariffs. The conducted study considers two types of unified tariffs, i.e., capacity and energy tariffs, and offers proper AS eliciting scheme for each type of unified tariffs. The main challenges addressed here are: 1) incentivizing\penalizing AS provision more\less than scheduled amount which is tackled through an incentive factor, and 2) preventing overall tariff increment (customer tariff) after eliciting AS tariff which is addressed by applying fixing constraint to the overall tariff at before and after AS tariff eliciting conditions [20]. Last but not the least, AS trade between adjacent utilities and calculating the benefits from this trade are addressed. The proposed approach is tested through numerical analysis for generic power plants. Fixed and variable cost parameters of the generic power plants are given in [19], [21].

II. PROPOSED METHODOLOGY

In this section, first, the proposed methodologies for eliciting AS tariff from capacity and energy tariffs are presented. Next, the proposed scheme for AS trade between

adjacent utilities and calculating the benefits of this trade is presented. The following assumptions are made in separating AS tariffs from unified tariffs:

• AS tariff is constant for two different type of spinning reserves: 1) Primary reserves, (frequency containment reserve FCR); and 2) Secondary reserves (frequency restoration reserve; FRR) [22]. In other words, there is a single AS tariff both for FCR and FRR. However, provision of FCR and FRR are remunerated separetely, based on the allocated reserve amount as illustrated in Fig. 2.

• AS providers are assumed to allocate spinning reserves based on power system operator requirements which are responsible from identifying total amount of spinning reserve requirements in term of FCR and FRR, separately.

• AS tariff is symmetrical in terms of upward and downward activation of FCR and FRR. For instance, if a power plant is allocated for providing 10% FCR, associated upper level for dispatch can be 90% of its capacity.
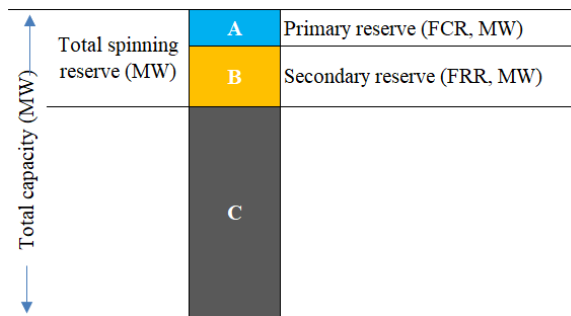

Fig.2. Spinning reserve concept in the proposed AS tariff mechanism

• Settling time is assumed to be one hour. That is, ancillary service tariff is in $/MW/h.

• No separate capacity tariff for tertiary reserves (i.e., replacement reserve, RR) and RRs are procured from the balancing market.

• It is assumed that upward and downward activation of FCR cancel each other gradually, as illustrated in Fig. 3. Therefore, there is no additional remuneration for the energy generated during the activation of FCR in the upward direction.

• In contrast to FCR, the amount of energy activated to provide FRR in both upward and downward directions, is subjected to balancing market. That is, the net energy balance of the AS providers should be remunerated in the balancing market, as illustrated in Fig. 3.

Figure 3 presents chronological activation of FCR, FRR, and RR after losing a generation unit in a typical power grid. Subsequent to this event, the frequency immediately starts decreasing (alteration #1 in Fig. 3). Here, the generation\demand balance is tried to be recovered through activating FCR in upward direction (#2). The frequency is restored to the pre-disturbance level by activating the FRR (#3) and RR (#6) in upward direction, respectively. This process ensures restoration of the FCR and FRR (downward activation) to their initial values as well. Although deployment of unified energy tariffs ($/MWh) is a common practice, some

countries implement capacity tariffs ($/MW/h) in addition to energy tariffs. Capacity tariff mechanisms are generally implemented to mitigate security and reliability concerns [18]. In economics, variable costs and fixed costs are the two main costs a company has when producing goods and services. A variable cost varies with the amount produced, while a fixed cost remains fix independent from the output. It is common to determine capacity tariffs with respect to the fixed-cost driven ARR of the power plants.
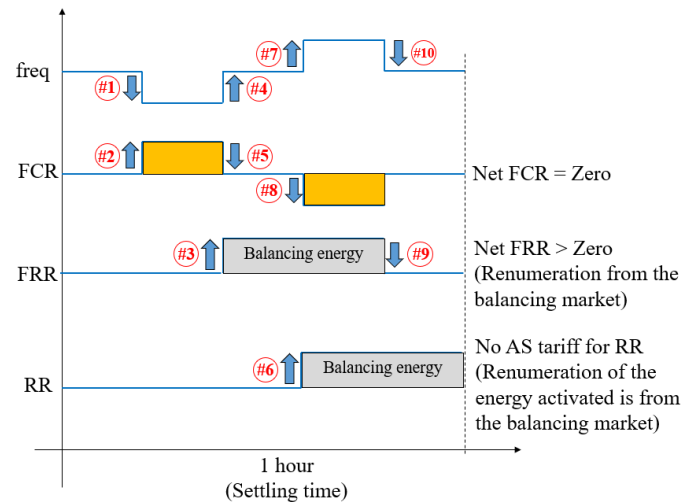
Fig. 3 Sequential activation of FCR, FRR, and RR after loss of generation.

Given the above-discussed assumptions, the proposed methodologies for eliciting AS tariff from unfied energy and capacity tariff are addressed in the following:

A. Eliciting AS Tariff from Unified Capacity Tariff (UCT)

Eliciting AS tariff from UCT ($/MW/h) is investigated in this section. The proposed methodology is based on fixed-costs driven ARR of the power plants. Figure 4 depicts the outline of the proposed approach.

Fig.4. Spinning reserve concept in the proposed AS tariff mechanism

Seperating AS tariff from the existing UCT should be made in a way that the power plants, which are supposed to provide AS reserve (either FCR, FRR, or both), should be remunerated if and only if they allocate and activate the AS reserve as planned by the transmission system operator (TSO). In this

respect, the following planning process by the TSO:

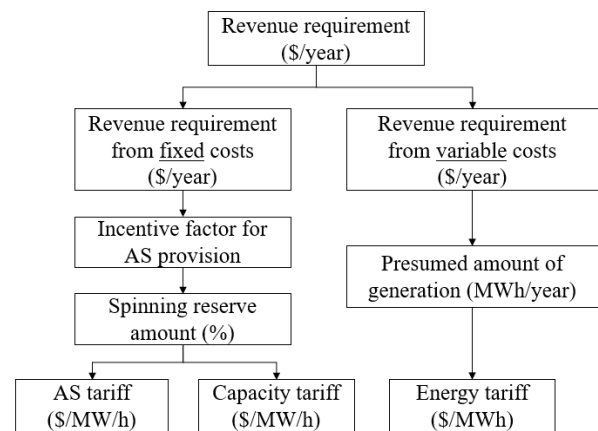• TSO should determine total amount of AS reserve (MW) required for the grid in terms of FCR and FRR. To do so the common practice is to determine them on a monthly basis at the initial phase of the market opening.

• Total AS reserve should be allocated to power plants based on their availability and technical capability to provide AS according to the grid code of the country. This requires a prequalification and certification process [23].

Unified cost-based capacity tariffs are determined by the regulatory authority based on ARRs of the power plants. Fixed-costs include the costs associated with the provision of AS services. The power plants are remunarated for their available capacity through their UCTs, as described by (1):

$$FC_i = \sum_{t=1}^{12} \left(UCT_i \times AVC_i^t \right) \tag{1}$$

where,

i	Generator index
t	Month index
FC_i	Annual fixed cost of the generator i ($/year)
UCT_i	Unified capacity tariff of generator i ($/MW)
AVC_i^t	Average available capacity of generator i at month t (A+B+C in Fig. 2) (MW)

AS tariff of each power plant is separated from the UCT in a way that, if it provides AS reserves as allocated; then, the summation of the payments from AS tariff and recalculated capacity tariff should be equal to payment from the current UCT. Mathematically speaking:

$$FC_i = \sum_{t=1}^{12} \left(CT_i \times AVCC_i^t + AST_i \times AVC_i^t \right) \tag{2}$$

$$AVC_i^t = AVCC_i^t + ASC_i^t \tag{3}$$

where ,

CT_i	Capacity tariff of generator i for $AVCC_i^t$ after separation of AS tariff ($/MW)
$AVCC_i^t$	Average available capacity excluding AS reserve (C in Fig. 2) (MW)
AST_i	Ancillary service tariff of generator i ($/MW)
ASC_i^t	Average available AS capacity of generator i at month t (A + B in Fig. 2) (MW)

Constant FC_i statisfies the second concern indicated above (i.e., increase of overall tariffs after separation of AS tariffs). Incentive factor, namely K, is for the second concern; to give incentives to those generators which are asked to provide more AS than planned, as illustrated in Fig. 5. The incentive factor K represents the slope in Fig. 5 which can be calculated as:

$$AST_i = K \times CT_i \tag{4}$$

If the slope is equal to one, total payment to generators is same as the case of UCT given by $CT_i = AST_i$. Here, the higher slope results in a greater gap between the AST_i and CT_i. The difference between AST_i and CT_i makes sense in terms of total payment to generators if they are asked to provide more AS than that of planned. In such a case, total payment to generators will increase. However if the power plant provides

less than planned, asoociated income will reduce which is caluated by (5). The incentive factor should be negotiated and settled between the power plants and ISO. Recalculation of the capacity tariff after separation of AS tariff is presented by (6).

$$FC_i = CT_i \times \sum_{t=1}^{12} \left(AVCC_i^t + K \times ASC_i^t \right) \tag{5}$$

$$CT_i = \frac{FC_i}{\sum_{t=1}^{12} \left(AVCC_i^t + K \times ASC_i^t \right)} \tag{6}$$
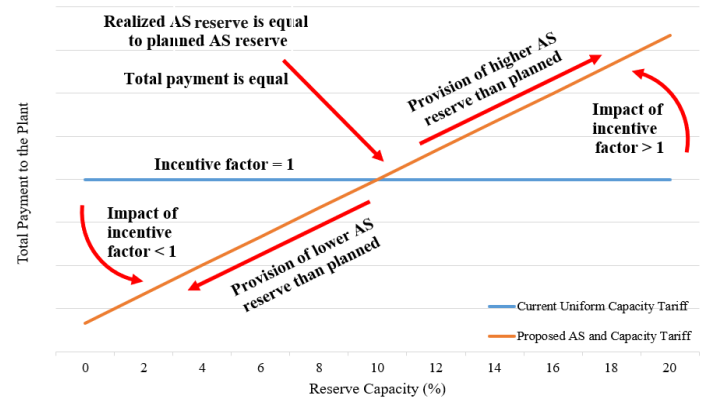
Fig. 5 Impact of incentive factor K for 10% allocated capacity

B. Eliciting AS Tariff from Unified Energy Tariff (UET)

Eliciting AS tariff from UET ($/MWh) is investigated in this section. The proposed methodology for separation of AS tariff from UCT (Section II.A) is modified as illustrated in Fig. 6. The methodology again starts by classifying fixed- and variable-costs of power plants and calculating fixed-cost based ARR of the power plants. However, since there is no capacity tariff, AST covers only fixed-costs which correspond to spinning reserves provision. The remaining fixed-costs should be converted to energy tariff as indicated in Fig. 6.

Fig.6. Flowchart of proposed methodology for eliciting AS tariff in case of UET

Equations (7)-(9) express the calculation process of *UET*, *AST*, and re-calculation of energy tariff after separation *AST*, respectively:

$$UET_i = \frac{FC_i + VC_i}{E_i} \tag{7}$$

$$AST_i = \frac{K \times FC_i}{E_i \times (1 - ASR_i) + ASR_i \times K} \tag{8}$$

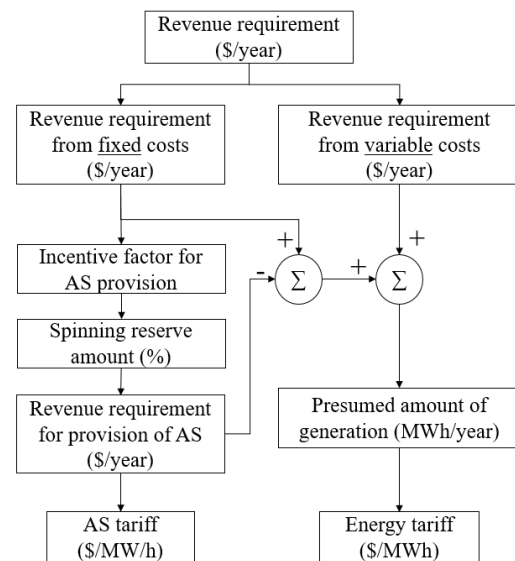$$ET_i = \frac{FC_i + VC_i - AST_i \times E_i \times ASR}{E_i} \tag{9}$$

where,

VC_i	Annual variable cost of the generator *i* ($/year)
E_i	Total amount of energy presumed to be produced by generator *i* (MWh/year)
ET_i	Enery tariff of power plant *i* ($/MWh) after separation of AST

To summarize the proposed approaches, Fig. 4 depicts the outline of the proposed approach for eliciting ancillary service from the tariff when unified capacity mechanism is applied. In the contrary, Fig. 6 represents eliciting ancillary service from the tariff when unified energy mechanism is applied. In brief, Fig 4 deals with capacity, however, Fig. 6 deals with energy.

III. NUMERICAL INVESTIGATIONS AND DISCUSSIONS

This section testifies effectiveness of the proposed method through numerical studies.

A. Eliciting AS Tariff from UCT

1) Illustrative Example 1 - Calculation of UCT

This example deals with calculation of *UCT*, *CT*, and *AST* for a generic thermal power plant for different values of incentive factor, *K*. Essentially, annual fixed costs of the power plant include those costs associated with the provision of AS services plus some profit to ensure that the power plants are satisfied with the tariffs. Table I and II represent the main parameters and fixed and variable costs of a generic thermal power plant. Note that profit ratio should be determined by the regulator. Here, profit ratio is assumed to be 10% and *UCT* is calculated as 3.52 $/MW/h through (10):

$$UCT = 7,392,000.00(\$)/300(MW)/7,000\ (h)$$
$$= 3.52\ \$/MW/h \tag{10}$$

TABLE I
MAIN PARAMETERS OF A GENERIC THERMAL POWER PLANT

Type of power plant	Thermal
Plant capacity (MW)	300
Availability hours per year (8760 - maintenance hours)	7,000
Full load hours per year	2,500
Estimated energy (MWh/year)	750,000 (300*2,500)
Annual operation hours (capacity factor)	3,333

2) Illustrative Example 1 - Calculation of AS Tariff

After calculating *UCT*, *AS* tariff should be calculated. Given that the generic power plant is committed to provide 10%

spinning reserve at real-time operation. *CT* and *ACT* are calculated using (1)-(6) for different incentive factors, *K*, as presented in Table III. For the calculations presented in Table III, it is assumed that the power plant allocates and activates 10% AS at the satisfactory level. Therefore, although total payment to the power plant from AS tariff increases along with incentive factor, total payment reamins fix (i.e., capacity payment plus AS payment). Such a behavior ensures the second concern in Fig. 1. Note that, capacity payment is significantly higher than that of AS in this example. The main reason is that *CT* is subjected to 90% of the power plant capacity during available hours (7,000 h); wheras, *ACT* is subjected to only 10% capacity of the power plant for operation hours (3,333 h), as presented in Table I.

TABLE II
FIXED AND VARIABLE COSTS OF A GENERIC POWER PLANT

Cost item	Fixed Cost (k$/year)	Variable Cost (k$/year)
Salary fund	1,500.00	-
Depreciation / amortization of production facilities	1,750.00	-
Expense on basic and supporting materials	200.00	-
Cost of operational maintenance	800.00	-
Fuel cost (natural gas, oil, coal, etc.)	-	25,000.00
Chemicals	-	10.00
Technical water consumption costs	-	15.00
Electricity utility and internal consumption costs	200.00	-
Utility costs (except electricity)	10.00	-
Communication expenses	10.00	-
Office cost	10.00	-
Business trips	5.00	-
Advisory costs	500.00	-
Security costs	50.00	-
Rental costs	5.00	-
Insurance expense	400.00	-
Market operator service fee	70.00	-
Commission regulation fee	60.00	-
property tax	200.00	-
Property tax on land	50.00	-
Other operating costs	100.00	-
Interest rate cost	650.00	-
Other non-operational costs	150.00	-
Total cost per year (k$/year)	**6,720.00**	**25,025.00**
Profit (10%)	**672.00**	**2502.50**
Total cost for tariff calculation (k$/year)	**7,392.00**	**27,527.50**

TABLE III
CT AND *ACT* CALCULATIONS FOR DIFFERENT INCENTIVE FACTORS

Incentive factor (K)	1	2	4
AS Reserve (Planned / Provided)	10% / 10%	10% / 10%	10% / 10%
CT($/MW/h)	3.52	3.36	3.08
ACT ($/MW/h)	3.52	6.72	12.32
Capacity Payment (k$/year)	**7,040**	**6,720**	**6,160**
AS Payment (k$/year)	**352**	**672**	**1,232**
Total Payment (AS+Capacity) (k$/year)	**7,392**	**7,392**	**7,392**

3) Illustrative Example 1 – Violating from scheduled amount of AS at real-time operation

Assume that the power plant is planned to provide 10% AS reserve; however, lower amount is realized in real-time operation. Consequently, associated revenue from AS tariff will considerably reduce. On the contrary, if asked to provide more than planned amount, associated revenue will increase with respect to the incentive factor, as presented in Table IV for the case of $K=2$.

TABLE IV
SCHEDULED VS PROVIDED (K=2)

Incentive factor (K)	2	2	2
AS Reserve	Planned: 10% Provided: **10%**	Planned: 10% Provided: **15%**	Planned: 10% Provided: **5%**
Capacity Tariff ($/MW/h)	3.36	3.36	3.36
AS Capacity Tariff ($/MW/h)	6.72	6.72	6.72
Capacity Payment (k$/year)	**6,720**	**6,552**	**6,888**
AS Payment (k$/year)	**672**	**1,008**	**336**
Total Payment (AS+Capacity) (k$/year)	**7,392**	**7,560**	**7,224**

4) Illustrative Example 2 – More than one power plant contribute to AS

In a case that a power plant is planned for AS provision; however, couldn't realize associated commitment in real-time operation, TSO should attain the required reserve from other power plants. In this illustrative example, such a condition is investigated through two different cases. In Case 1, five generic power plants (see Fig. 7) are considered to provide satisfactory level of spinning reserves which are subjected to provide 5% spinning reserve (Case 1). The scheduled and provided AS for these power plants are illustrated in Fig. 8. In Case 2, it is assumed that generic power plant B refuses to provide AS at a satisfactory level, and hence, generic power plant F is providing 5% more spinning reserve given that both plants have the same capacity as illustrated in Fig. 8 (Case 2). *UCT, CT,* and, *AST* of the power plants are presented in Fig. 7. Incentive factor, *K*, is assumed to be 2.
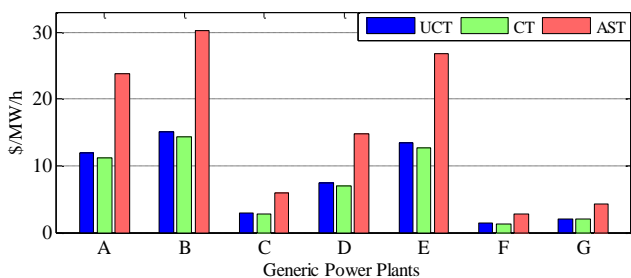
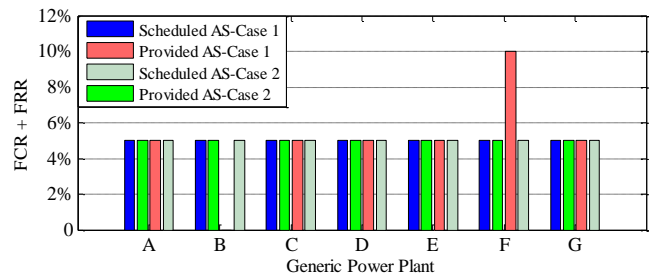Fig.7. *UCT, CT,* and, *AST* of the generic power plants (*K*=2)

Fig.8. Scheduled versus provided AS reserve by the generic power plants (Cases 1 and 2)

Note that generic power plant F is selected to provide additional AS owing to low *AST* in comparison to the other power plants of this example. It is worth mentioning that tariffs of the power plants are disregarded while scheduling and allocating spinning reserve requirement among the power plants. Such an indicator could be considered; however, it might be out of scope of conducted study.

Annual payments to power plants for Case 1 and 2 are represented in Fig. 9 and Fig. 10, respectively. Total payment to power plant B reduces in Case 2 comparing to Case 1 as power plant B is excluded from *AST* payment. In Case 2, total payment to the plant F is more than that of Case 1 since the incentive factor greater than 1, i.e. K = 2.
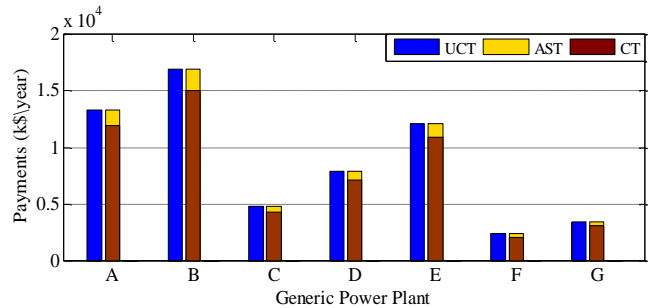
Fig.9. Annual revenue from *UCT, CT,* and, *AST* in Case 1
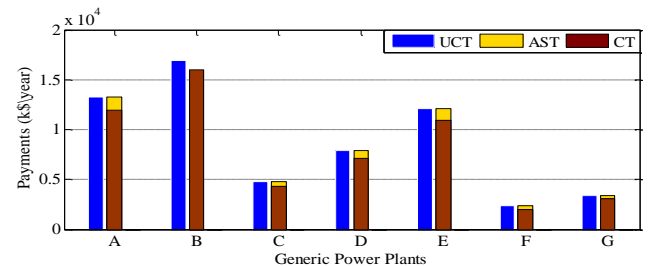
Fig.10. Annual revenue from *UCT, CT,* and, *AST* in Case 2

B. Eliciting AS Tariff from UET

In this example, the same condition as that of illustrative examples presented in Section III.A are considered; unless, the power plants are assumed to be subjected to *UET*. That is ARR of the power plant is remunarated through *UET* . In this numerical example, *FC*= 27,528.00 k$/year; *VC*= 7,392.00 k$/year; *E*= 750,000 MWh/year. *UET* of the generic power plant is 4.66 $-cent/kWh which can be calculated as:

$$UET = \frac{27528 + 7392}{750000} \times 100 = 4.66 \, \$-\text{cent/kWh} \qquad (11)$$

AST of the power plant is 0.99 $-cent/kW/h (12):

$$AST = \frac{K \times FC_i}{E_i \times (1 - ASR_i) + ASR_i \times K} = 0.99 \ \$-cent/kW/h \quad (12)$$

where, *ASR* is ancillary service in per units. Finally, energy tariff will be 4.56 $-cent/kWh (13). As can be seen, after separation of *AST*, *ET* is lower than *UET* (i.e., 4.56 < 4.66).

$$ET_i = \frac{(FC_i + VC_i) - AST_i \times E_i \times ASR_i}{E_i} = 4.56 \ \$-cent/kW/h \quad (13)$$

C. Calculation of Benefits of Countries from AS Coupling

In this section, numerical analyses are performed to calculate benefits of two countries from coupling their AS and balancing mechanisms, based on the proposed cost-based AS tariffs eliciting approach. The following direct benefits are addressed:

- **Common Dimensioning**: It is an opportunity for TSOs to jointly dimensioning the total volume of balancing reserve, as illustrated in Fig. 11.

- **Exchange of Reserve**: It is the opportunity for TSOs to procure part of the balancing energy in another area (with no impact on the total amount of balancing reserve in the system) as illustrated in Fig. 11. The scenarios investigated here are summarized in Table V. In Fig. 11, three different conditions are depicted. First, each region holds spinning reserves based on their own need. In the common dimensioning, both side are holding 150 MW spining reserve as a common reserve. Finally, for exchanging reserve case, the 20 MW reserve is exchanged between the regions.
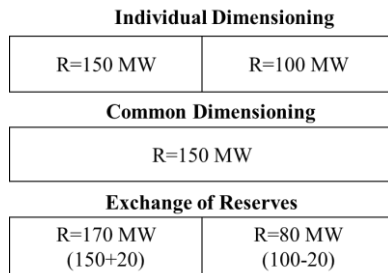
Individual Dimensioning

R=150 MW	R=100 MW

Common Dimensioning

R=150 MW

Exchange of Reserves

R=170 MW (150+20)	R=80 MW (100-20)

Fig.11. Direct benefits from coupling of AS (R: amount of allocated spinning reserve)

TABLE V
SCENARIOS INVESTIGATED IN SECTION III.C

Scenario	Condition	AS and Balancing Coupling
1	No interconnection between countries A and B	-
2	Interconnection between country A and B	Common dimensioning
3	Interconnection between country A and B	Exchange of AS reserves

1) Key Assumptions

Given two interconnected countries, five power plants each with 100 MW capacity are assumed in both countries. Each power plant provides 20% spinning reserve, totally 100 MW, to compensate for loss of any power plant in the countries.

Available hours of the power plants are assumed to be 7,000 h. The following annual parameters are assigned differently among the power plants to differentiate their cost-based tariffs: i) In-service hours, ii) Total fixed costs. More details of the assumptions are described in the Sections III.C.2, III.C.3, and III.C.4 on a country basis.

Parameters of the power plants and associated *CT* and *AST* are provided in Tables VI and VII for Country A, and Tables VIII and IX for Country B, respectively. Incentive factor, *K*, is assumed to be 1.5 in all power plants. Additional cost of power plants due to provision of AS is assumed to be 10% of corresponding fixed costs.

TABLE VI
PARAMETERS OF THE POWER PLANTS – COUNTRY A

Parameter	G.A.1	G.A.2	G.A.3	G.A.4	G.A.5
Plant Capacity (MW)	100	100	100	100	100
Estimated Availability Hours (h)	7,000	7,000	7,000	7,000	7,000
In service hours along the year (h)	3,300	6,000	5,000	3,000	5,000
FC (k$/year)	2	2,500	3	2,500	3,500
Additional costs related to AS (%)	10%	10%	10%	10%	10%
Profit (10%)	10%	10%	10%	10%	10%
Spinning reserve (%)	20%	20%	20%	20%	20%
ARR from CT and AST (k$/year)	2,420	3,025	3,630	3,025	4,235

TABLE VII
TARIFF CALCULATIONS – COUNTRY A

Parameter	G.A.1	G.A.2	G.A.3	G.A.4	G.A.5
UCT ($/MW/h)	3.46	4.32	5.19	4.32	6.05
K	1.5	1.5	1.5	1.5	1.5
CT ($/MW/h)	3.30	3.98	4.84	4.14	5.65
AST ($/MW/h)	4.95	5.97	7.26	6.22	8.47

TABLE VIII
PARAMETERS OF THE POWER PLANTS – COUNTRY B

Parameter	G.B.1	G.B.2	G.B.3	G.B.4	G.B.5
Plant Capacity (MW)	100	100	100	100	100
Availability hours (h)	7,000	7,000	7,000	7,000	7,000
In service hours (h)	3,300	6,000	5,000	3,000	5,000
FC ($/year)	1	1,250	1,500	1,250	1,750
Additional costs related to AS (%)	10%	10%	10%	10%	10%
Profit (10%)	10%	10%	10%	10%	10%
Spinning reserve (%)	20%	20%	20%	20%	20%
ARR from CT and AST (k$/year)	1,210	1,513	1,815	1,513	2,118

TABLE IX
TARIFF CALCULATIONS – COUNTRY B

Parameter	G.A.1	G.A.2	G.A.3	G.A.4	G.A.5
UCT ($/MW/h)	1.73	2.16	2.59	2.16	3.03
K	1.5	1.5	1.5	1.5	1.5
CT ($/MW/h)	1.65	1.99	2.42	2.07	2.82
AST ($/MW/h)	2.48	2.99	3.63	3.11	4.24

CT and *AST* of power plants in Country B are less than those of Country A as illustrated in Fig. 12. Difference is mainly due to fixed cost parameters of the power plants (see Table VI and Table VIII).
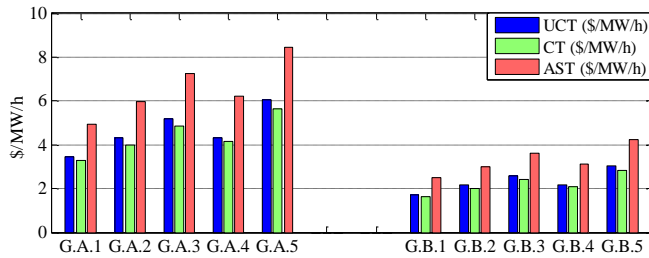
Fig.12. *CT* and *AST* of power plants – Country A vs Country B

2) Scenario 1 – No interconnection between Country A and Country B

In case of no interconnection between the countries, the payments to power plants located at Countries A and B from *CT* and *AST* are calculated as presented in Table X and Table XI, respectively.

TABLE X
CALCULATIONS OF PAYMENTS FOR CT AND AST – COUNTRY A

Parameter	G.A.1	G.A.2	G.A.3	G.A.4	G.A.5
Capacity Payment from CT (k$/year)	2,093	2,308	2,904	2,652	3,388
Total Payment from CT (k$/year)			13,346		
AS Payment from AST (k$/year)	326	716	726	372	847
Total Payment from AST (k$/year)			2,989		
Total Payment for CT and AST (k$/year)	2,420	3,025	3,630	3,025	4,235
Total Payment for CT and AST (k$/year)			16,335		

TABLE XI
CALCULATIONS OF PAYMENTS FOR CT AND AST – COUNTRY B

Parameter	G.A.1	G.A.2	G.A.3	G.A.4	G.A.5
Capacity Payment from CT (k$/year)	1,047	1,154	1,452	1,326	1,694
Total Payment from CT (k$/year)			6,673		
AS Payment from AST (k$/year)	163	358	363	186	423
Total Payment from AST (k$/year)			1,495		
Total payment for CT and AST (k$/year)	1,210	1,512	1,815	1,512	2,117
Total payment for CT and AST (k$/year)			8,168		

3) Scenario 2 – Common Dimensioning

In this scenario, it is assumed that two countries are interconnected and they implement common dimensioning for their AS and balancing requirements. After common dimensioning, the amount of AS allocation in both countries reduces to 50 MW representing total spinning reserve of 100 MW. Each country is assumed to reduce spinning reserve amounts from those power plants which have the highest *AST*. This reduction will occur in G.A.5, G.A.3, and G.A.2 in Country A, and G.B.5, G.B.3, and G.B.4 in Country B given their high relatively high *AST*, as illustrated in Table XII and Table XIII, respectively. The tables also present recalculated

values of ARRs to be recovered from *CT* and *AST*.

TABLE XII
RECALCULATION OF PARAMETERS - COUNTRY A

Parameter	G.A.3 (1)	G.A.3 (2)	G.A.4 (1)	G.A.4 (2)	G.A.5 (1)	G.A.5 (2)
Plant capacity (mw)	100	100	100	100	100	100
Estimated Availability Hours per year (h)	7,000	7,000	7,000	7,000	7,000	7,000
In service hours along the year (h)	5,000	5,000	3,000	3,000	5,000	5,000
Total cost for CT calculation (k$/year)	3,000	3,000	2,500	2,500	3,500	3,500
Costs related to AS provision (%)	10%	0%	10%	10%	10%	0%
Costs related to AS provision (k$/year)	300	-	250	250	350	-
Profit (10%)	10%	10%	10%	10%	10%	10%
Spinning reserve (%)	20%	0%	20%	10%	20%	0%
Total spinning reserve amount (MW)	20	-	20	10	20	-
ARR from CT and AST per year (k$/year)	3,630	3,300	3,025	3,025	4,235	3,850

TABLE XIII
RECALCULATION OF PARAMETERS - COUNTRY A

Parameter	G.A.3 (1)	G.A.3 (2)	G.A.4 (1)	G.A.4 (2)	G.A.5 (1)	G.A.5 (2)
Plant capacity (mw)	100	100	100	100	100	100
Estimated Availability Hours per year (h)	7,000	7,000	7,000	7,000	7,000	7,000
In service hours along the year (h)	5,000	5,000	3,000	3,000	5,000	5,000
Total cost for CT calculation (k$/year)	1,500	1,500	1,250	1,250	1,750	1,750
Costs related to AS provision (%)	10%	-	10%	10%	10%	-
Costs related to AS provision (k$/year)	150	-	125	125	175	-
Profit (10%)	10%	10%	10%	10%	10%	10%
Spinning reserve (%)	20%	0%	20%	10%	20%	0%
Total spinning reserve amount (MW)	20	-	20	10	20	-
ARR from CT and AST per year (k$/year)	1,815	1,650	1,513	1,513	2,118	1,925

Since G.A.3, G.A.5, G.B.3, and G.B.5 are not providing AS, their total annual fixed cost reduces since AS provision payment is excluded. This reduction will essentially reduce their *CT*s, as illustrated in Fig. 13. Note that, although these power plants will not provide AS, their capacity connected with AS in Scenario 1 should be still be remunerated through the *CT* in Case 2. That is, total capacity subjected to *CT* in Case 2 increases if compared to Case 1 by the amount of spinning reserve allocated in Case 1, as illustrated in Fig. 14. Nevertheless, total payments of country A and B for *CT* and *AST* reduces as presented in Fig. 15. This result shows that total savings of Countries A and B from common dimensioning is 1,073 k$/year for this particular generic example. Note that ARRs of G.A.4 and G.B.4 from *CT* and

AST remained fixed given the assumption that costs related to AS provision do not change along with reduction of AS amount from 20% to 10%.
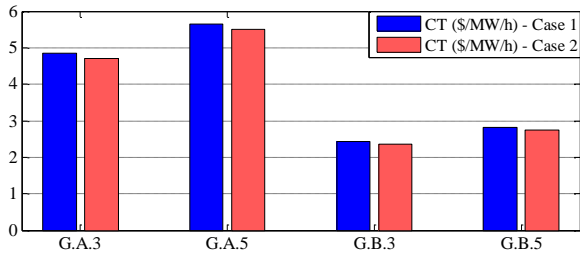

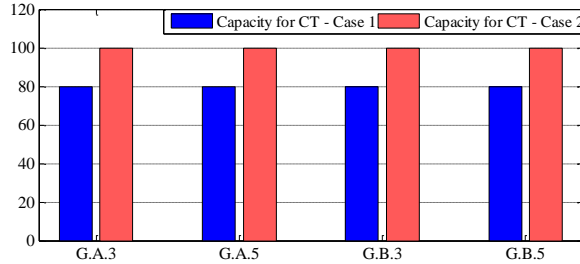Fig.13. *CT* of G.A.3, G.A.5, G.B.3, and G.B.5 (Case 1 vs Case 2)

Fig.14. Capacity of G.A.3, G.A.5, G.B.3, and G.B.5 subjected to *CT* (Case 1 vs Case 2)
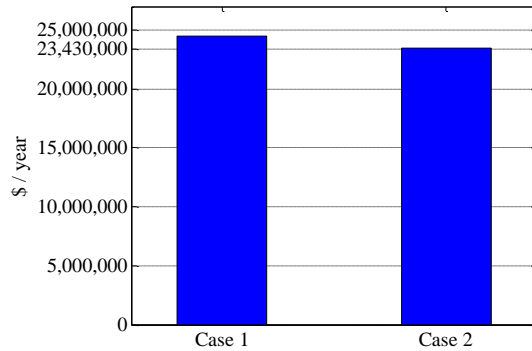

Fig.15. Total payment for *CT* and *AST* (Country A + Country B)

4) Scenario 3 – Exchange of AS

In this scenario, it is assumed that Countries A and B are exchanging 20 MW spinning reserve. The exchange is between G.A.1 and G.B.1. That is, G.A.1 is not providing any spinning reserve while G.B.1 is providing additional 20 MW to compensate for. This exchange still ensures 100 MW total spinning reserve in total (i.e., Country A plus Country B). Re-calculated values of ARRs, tariffs, and payments are provided in Table XIV-Table XVI for Country A, and Table XVII-Table XIX for Country B, respectively.

Benefits of the countries from AS and coupling mechanisms are presented in Fig. 16. One can argue that the benefit is not observable and relatively small. However in the numerical analysis, normalized fixed costs ($/MW) of the power plants are assumed almost similar in order to be realistic (fixed cost range is taken from the literature [19], [21]. In addition, profit component of the power plants (10%) and incentive factor (*K*=1.5) are assumed to be same. Such parameters can result in higher benefits than calculated in the generic numerical examples. Nevertheless, main focus is given in the study to

propose an AS tariff separation methodology which satisfies the main concerns mentioned above.

TABLE XIV
RECALCULATION OF PARAMETERS - COUNTRY A

Parameter	G.A.1	G.A.2	G.A.3	G.A.4	G.A.5
Plant Capacity (MW)	100	100	100	100	100
Estimated Availability Hours per year (h)	7,000	7,000	7,000	7,000	7,000
In service hours along the year (h)	3,300	6,000	5,000	3,000	5,000
Total cost for CT calculation ($/year)	2,000	2,500	3,000	2,500	3,500
Costs related to AS provision (%)	-	10%	-	10%	-
Costs related to AS provision ($/year)	-	250	-	250	-
Profit (10%)	10%	10%	10%	10%	10%
Spinning reserve (%)	-	20%	-	10%	-
Total spinning reserve amount (MW)	-	20	-	10	-
ARR from CT and AST per year ($/year)	2,200	3,025	3,300	3,025	3,850

TABLE XV
RECALCULATION OF CT AND AST - COUNTRY A

Parameter	G.A.1	G.A.2	G.A.3	G.A.4	G.A.5
CT ($/MW/h)	3.14	3.98	4.71	4.23	5.50
AST ($/MW/h)	-	5.97	-	6.35	-

TABLE XVI
RECALCULATION OF PAYMENT - COUNTRY A

Parameter	G.A.1	G.A.2	G.A.3	G.A.4	G.A.5
Capacity Payment from CT (k$/year)	2,200	2,309	3,300	2,835	3,850
Total Payment from CT (k$/year)	14,493				
AS Payment from AST (k$/year)	-	716	-	190	-
Total Payment from AST (k$/year)	907				
Total Payment for CT and AST (k$/year)	2,200	3,025	3,300	3,025	3,850
Total Payment for CT and AST (k$/year)	15,400				

TABLE XVII
RECALCULATION OF PARAMETERS - COUNTRY B

Parameter	G.A.1	G.A.2	G.A.3	G.A.4	G.A.5
Plant Capacity (MW)	100	100	100	100	100
Estimated Availability Hours per year (h)	7,000	7,000	7,000	7,000	7,000
In service hours along the year (h)	3,300	6,000	5,000	3,000	5,000
Total cost for CT calculation ($/year)	1,000	1,250	1,500	1,250	1,750
Costs related to AS provision (%)	10%	10%	-	10%	-
Costs related to AS provision ($/year)	10%	10%	10%	10%	10%
Profit (10%)	20%	20%	-	10%	-
Spinning reserve (%)	1,210	1,513	1,650	1,513	1,925
Total spinning reserve amount (MW)	100	100	100	100	100
ARR from CT and AST per year ($/year)	7,000	7,000	7,000	7,000	7,000

TABLE XVIII
RECALCULATION OF CT AND AST - COUNTRY B

Parameter	G.A.1	G.A.2	G.A.3	G.A.4	G.A.5
CT ($/MW/h)	1.65	1.99	2.36	2.12	2.75
AST ($/MW/h)	2.48	2.99	-	3.17	-

TABLE XIX
RECALCULATION OF PAYMENT - COUNTRY B

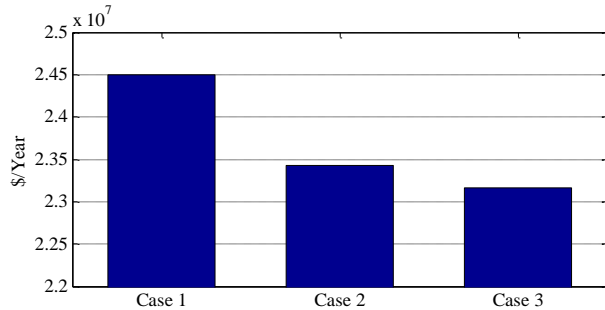| Parameter	G.A.1	G.A.2	G.A.3	G.A.4	G.A.5
Capacity Payment from CT (k$/year)	938	1,154	1,650	1,417	1,925
Total Payment from CT (k$/year)			7,084		
AS Payment from AST (k$/year)	229	358	-	95	-
Total Payment from AST (k$/year)			682,840.28		
Total Payment for CT and AST (k$/year)	1,167	1,513	1,650	1,513	1,925
Total Payment for CT and AST (k$/year)			7,767		

Fig.16. Total payment for *CT* and *AST* (Country A + Country B)

IV. DISCUSSIONS AND CONCLUSIONS

This study dealt with eliciting AS tariffs from unified capacity and energy tariffs through a cost-based approach. In the proposed framework, maintaining annual revenue requirements of the power plants are considered as the main objective while separating the AS tariff from unified tariffs. The conducted study addressed the following challenges: 1) incentivizing\penalizing AS provision more\less than scheduled amount which is tackled through an incentive factor, and 2) preventing overall tariff increment (customer tariff) after eliciting AS tariff which is addressed by applying fixing constraint to the overall tariff at before and after AS tariff eliciting conditions. Main concern of power plants in providing AS is the additional costs connected with providing active power regulation and loss of opportunity due to allocation of some reserves of AS provision. On the other hand, main concern of transmission system operator and electricity market regulatory authorities is remunerating the power plants which do not provide AS, through unified tariffs. Numerical case studies demonstrated that the proposed approach satisfies such concerns. In addition, electricity market regulatory authorities of the countries, which implement unified capacity and/or energy tariffs, can consider the proposed tariff separation approach for determining true cost level of their country in procuring AS. Therefore, such countries do not need to wait until market opening to start benefitting from AS coupling with neighbour countries. The proposed approach enables them to quantify their benefits.

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