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Simulating Zonal Pricing in East African Electricity Markets

Geoffrey Aori Mabea

Energy Regulators Association of East Africa, Energy Regulation Centre of Excellence, Arusha, Tanzania

Email address:
geoffrey.mabea@gmail.com

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Abstract: The East African electricity markets are due to fully couple and embrace short term trading. Traditionally, excess generation in any country has to be bilaterally traded or delayed signing Power Purchase Agreements to avoid capacity charges. However, in recent years, with increased pressure to increase energy access in the region, the Eastern Africa Power Pool (EAPP) has been established to introduce robust bilateral and short-term markets. Price signals are critical to determining investment levels in a competitive electricity market. Therefore, this research aims to investigate the feasibility of bidding zones using clustering methodology in selected East African Countries. This paper simulates a zonal wholesale market with optimal power flow and k-means clustering theory to identify optimal bidding zones strategies and determine Nash-equilibrium prices. The results indicate that when the markets engage in the wholesale markets with planned transmission investment, the configuration of three optimal zones induces the highest welfare level. Therefore, this research informs the Eastern Africa and the African Union energy policy debate on the African Single Electricity Market and the Eastern Africa Power Pool electricity market dilemma.

Keywords: Electricity Markets Integration, Clustering Theory, Zonal Pricing, Congestion, Optimal Power Flow, Simulation

1. Introduction

The East African Community (EAC) Partner States have varying power demands. Therefore, depending on the installed capacity level, a country with a low electricity demand but high generation capacity could benefit from selling the extra capacity through an integrated system to a country with high demand but low capacity.

Table 1. *Electricity generation and consumption.*

Country	Generation (MW)	Consumption (MW)	Consumption per (KWh/year)
Burundi	88.25	62.93	23
Kenya	2819	1913	155.4
Rwanda	225.5	140.61	55.64
Uganda	1258.2	699.34	101.55
Tanzania	1845.2	1208.56	182.415

Source: Energy Regulators Association of East Africa [1]

For example, in Table 1, Uganda and Rwanda have high electricity reserve margins rates of 80% and 60% and a corresponding generation of 1258.2MW and 225.5MW, respectively. On the other hand, Kenya, Tanzania and Burundi have low generation capacity compared to consumption. Therefore, it is befitting if the low-cost extra resource is transmitted to the integrated market to benefit countries like Uganda and Rwanda, which have high demand but low generation capacity. The introduction of integrated electricity markets encourages competition and improves the investment environment for successor investors. This competition further lays a good foundation and promotes private sector involvement in the power sector, especially in the power production component. If the markets are not integrated, the efficiency arising from cost saving is limited. The concept of power systems optimisation is based on either operation or planning [2]; the operation deals with making fair use of the existing facilities/ power plants while the planning component lays down the investment in either transmission infrastructure or generation. This paper examines both the operation component, i.e., the congestion management and the planning component, which impacts the investment in renewable energy and transmission expansion. The essence of studying congestion management is to identify a suitable congestion management system that yields increased competition and welfare, thus improving the power supply's efficiency at the EAC power system. The low-cost node will save on operation and even capital costs when markets integrate since the power can be wheeled from the low-cost neighbouring node.

Investment in renewable generation reduces the carbon footprint, and the risks associated with insufficient demand can be pooled if the markets are integrated [3, 4]. Considering the electricity markets' operation, energy auction has become the central platform for interaction between the producers and the consumers. On the other hand, in perfect competition, market behaviour denotes a situation where each generator's production is negligible compared to all the firms' total generation. The nodal price represents the shadow price at the power balance at a given bus. The Locational Marginal Pricing (LMP)/nodal pricing acknowledges location or node position, which is vital and is reflected in the final electricity price. This is different from zonal pricing, where there is a uniform price in each region or country regardless of the transmission congestion expected in the region.

A zone is represented as a country (for example, U.K.) or a region connecting more than one power exchange (E.U.). A zonal price is arrived at when an energy auction results in a uniform price for a region or even a country regardless of transmission capacity constraints for a given region [5]. Alternatively, when the nodal prices with slight differences are clustered together. The nodal prices and zonal prices are impacted by other factors such as congestion in a line and the marginal cost of production. For example, renewable resources such as solar, wind and hydro have almost zero marginal cost of production. Since the marginal cost of production determines the nodal price, the overall price will be less. The study on renewable energy into an integrated electricity market has attracted many studies [6-9]. However, no study has been carried out at the EAC to assess the economic welfare impact since an integrated market has yet been designed and established. The closet research has been carried out by Mabea on the optimal transmission capacity under a nodal pricing market and determination of price zones [10, 11].

Therefore, this paper aims to investigate the feasibility of bidding zones and how they can affect the future of the EAC power markets.

2. Theory of Electricity Markets

2.1. Locational Pricing

The shadow price at the power balance at a given bus gives the bus's Locational Marginal Pricing (LMP). The LMP/nodal pricing acknowledges location or node position, which is vital and is reflected in the final electricity price. This is different from zonal pricing, where there is a uniform price in each region or country regardless of the transmission congestion expected in the region.

The LMP design is based on the nodal price concept, a point in the network being equal to the marginal cost of energy at that node [12]. It was first developed by Schweppe, Caramanis, Tabors, and Bohn under the assumption that if an Optimal Power Flow (OPF) solution is obtained for a given system, competition in the market can be reached. This implies that given a generator paying at LMP for energy supplied and ancillary services for a given bus, the OPF's optimal solution at that specific bus for the generator is also profit maximising for the firm. Nodal pricing has been implemented in countries like Argentina, Chile, New Zealand, Russia, Singapore and some U.S. states; for example, California, New England, New York, PJM and Texas [13, 14]. Moreover, several pieces of research ascertain the benefits of moving from zonal to nodal pricing, for example, in Van der Weijde & Hobbs and Ignacio, Lete, Papavasiliou and Smeers [15, 16].

Green explores the impact of integrating intermittent renewable energy into the British system to evaluate the adequacy of the spatiality of prices and bilateral trading to respond to changes in generation and demand. The study argues that nodal pricing induces efficient allocation, especially in competitive markets where the demand is uncertain and renewable energy production is prevalent [17]. Ruderer & Zöttl (2014) compare LMP versus zonal or one price market designs based on the type, generation technology and the investment level in the transmission network and conclude that both designs deliver efficient dispatch but uniform pricing as the one used in the British system may result in higher payoff to generators. However, the application of uniform pricing can lead to distortion of the generation technology mix and thus lead to inefficient investment in the transmission infrastructure. Locational Marginal Pricing model has also been compared to market coupling in large markets. Oggioni, Murphy and Smeers compare LMP and Market coupling where the wind technology policies and many economic agents exist in the power system. The study observes that LMP and Market's coupling evolve similarly, as long as wind penetration is constrained to a particular limit. However, LMP pricing exhibits stability even when the limit is exceeded [18].

LMP has been identified as one of the efficient ways of congestion management and, to no small extent, is evidence of efficient production investment [19-23]. A detailed derivation of the nodal pricing is in the appendix.

2.2. Zonal Pricing

This technique has two parts: zonal clearing and re-dispatch (counter trading). A zone is represented as a country (for example, the U.K.) or a region connecting more than one power exchange (E.U.). Energy auction results in a uniform price for a region or even a country, regardless of transmission capacity constraints for a given region. This has been applied in Australia, Denmark, Sweden, and Britain [24]. However, Britain adapts zonal pricing only in the Day-Ahead Market (DAM) while discriminatory pricing is applied in the real-time market. The U.S. also implemented Zonal pricing but later changed it into LMP [25]. Europe is characterised by zonal pricing; Egerer, Weibezahn, and Hermann evaluated the potential impact of creating a different bid zone for the German electricity market in 2012 and 2015 and observed that minimal declension of re-dispatch levels between the two bidding zones and price differences were significant, especially during high regional imbalance suggestive of regional investment incentive in supply and demand in the long run [26].

The development of market coupling is built on welfare maximisation theory and auction theory. The market's main objective is to maximise the economic welfare of the day ahead market subject (maximising the welfare of the accepted bids) to prevailing constraints such as market constraints, power balance constraints, power flow constraints, and net position ramping constraints. Other minor constraints include duality and primal constraints.

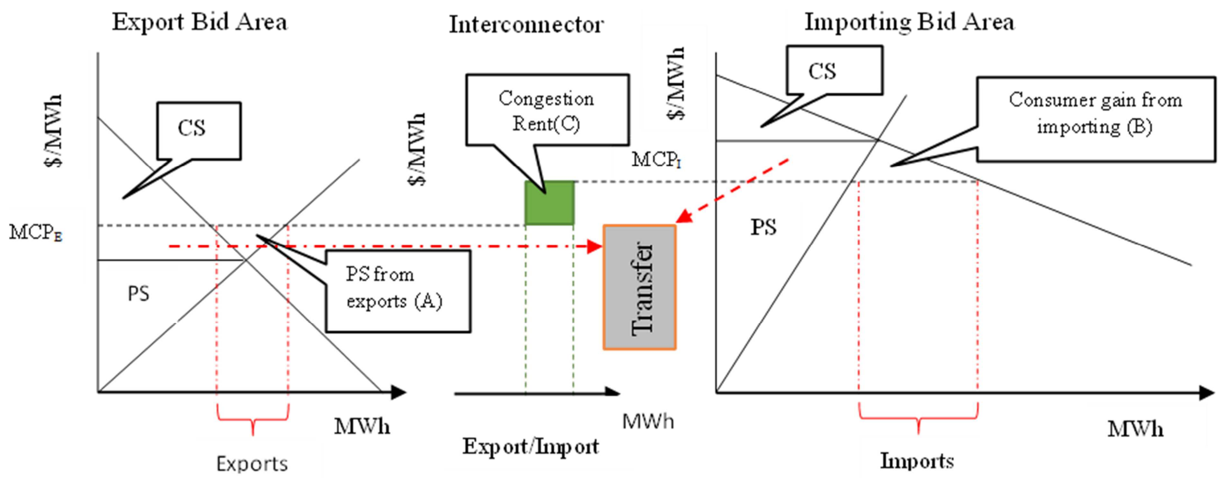

Figure 1. *Welfare effects arising from Electricity Markets Coupling: Adapted from E-Bridge [27].*

The congestion rent is given by Export/ Import flow multiplied by (MCP_I-MCP_E). The total social welfare arises due to the effects of coupling two electricity bidding areas (exporting and importing). These are arrived at through the summation of the consumer surpluses, bidder (generator surpluses) and the congestion rent due to the physical transmission constraint. The price differences could be because other factors like physical constraints or losses in the network create the variance in the evolution of the surpluses.

The transfers indicate the redistributed consumer and producer surpluses as a result of the market coupling, which, according to Ochoa and Ackere, explain that some market participants loose while others gain when coupling occurs, and therefore a suitable compensation needs to be developed; though again the study points out that if it must be done, then caution must be exercised to avoid giving wrong market signals [28].

3. Electricity Markets Coupling

Market coupling is a technique of integrating different electricity markets into one whole market [29]. This means that the demand and supply of electricity orders are not confined or restricted to one market or country. Different markets are taken as one seamless entity, with the transmission network remaining the only constraint. With market coupling, the purchase of transmission rights is eliminated. This, therefore, is seen to mitigate against price volatility and enhance liquidity in the market because the market size is increased, leading to maximisation of economic welfare [30].

Market coupling is used to manage congestion problems, determine optimal electricity direction of flow, the quantity (volume) of the flow, determine the price of electricity flows between any connected markets and increase the security of supply. Under coupling, it is the duty of the Transimission System Operators (TSOs) and the Power Exchanges (P.X.s) to ensure adequate power flows and ensuring optimisation such that the high-cost node benefits from the low-cost node. The market coupling has taken root in the European Union. The seven PXs are now using a single algorithm to clear the markets under the Price Coupling of Regions (PCR), a project referred to as the European Commission's Target Electricity Model (TEM). Details on the European market coupling developed in 2008 are detailed by Derinkuyu [31].

4. Models for Market Coupling

Market coupling is classified into explicit auctions, implicit auctions, and market splitting. Explicit auction is when the transmission and electricity capacities are traded at different markets [32]. These typically apply long-term Capacity Allocations (at least yearly and monthly period), which has two approaches in its calculation, i.e., Coordinated net transmission capacity-based approach and the flow-based approach with associated firm transmission rights subject to Use-It-Or-Lose-It (UIOLI) or Use-It-Or-Sell-It (UIOSI) principles [33]. On the other hand, the implicit auction is when there is a connection between two spot markets and the auction of the transmission capacity is integrated into the electricity auction. This implies that if the buyers of electricity bid for a particular electricity capacity from a generator, the price at which the energy is sold reflects the price of the transmission capacity [34]. In other words, the cost of generation and the congestion cost are reflected in the final price of electricity. Therefore, under this model, the arbitrage is impliedly internalised into the power exchanges' auction algorithm, thus resulting in increased price convergence. These capacity allocations involve both day-ahead and intraday Capacity Allocation. Under market Splitting, sometimes the electricity price within an area can differ slightly, especially when the convergence of prices is imperfect due to limited transmission capacity. Because of the price differences, a 'split' of the market occurs. To manage the congestion, splitting the market becomes invertible. Through market splitting, levelling of price differences is achieved in that the high-cost node is reduced, and likewise, the low-cost node is increased, thereby increasing the economic welfare [35]. This is sometimes called price zoning.

5. Data Description and Methodology

The electricity market involves both the physical market and the financial market. The physical market includes the network of generation, the demand nodes and the transmission line system, which rely on Kirchhoff's laws [36].

5.1. Model Formulation of the Power Flow

Notation

1) n ϵ N: Set of Nodes;
2) l ϵ T: Lines of Transmission grid;

Parameters

1) $g_{i,n}$: Capacity of plant type at node n (MWh)
2) $C^{c}_{(i,n)}$: Cost of existing conventional power plant at node n($/MWh)
3) d_n: Power consumption by consumers located at node n(MWh)
4) $P_n(d_n)$: Inverse demand function at node n
5) λ is the reduced form of the energy balance Lagrange multiplier vector
6) $\varphi_l^{h\pm}$: Congestion rent depending on the direction of flow
7) $\widetilde{\omega}_j$ $\widetilde{\omega}_i$: KKT multipliers for line flow limit and generation capacity
8) $PTDF_{1,n}$: Power Transfer Distribution Factor matrix of node n on line l
9) T_i: Transmission limit through line l(MWh)
10) $g_{i,n}$: Power generated by existing unit in node n(MWh)
11) $g_{i,n,max}$: Maximum generation capacity
12) F_{Lmax} Maximum line flow limit
13) $Conventional$: Conventional power plant parameters
14) Ke, Tz, Br, Rw, Ug : Country abbreviations (Kenya, Tanzania, Burundi, Rwanda, Uganda

The total welfare of all the firms is shown in equation (1) below

$$\text{Max}\left\{\sum_{n=1}^{17}\int_0^{d_n^{(Ke,Tz,Br,Rw,Ug)}} P_n(d_n)dq - \sum_{i=1}^{17}\int_0^{g_n^{(Ke,Tz,Br,Rw,Ug)}} \left(C^{c}_{(i,n)}\right) * \left(g_{i,n}\right) dg_{Conventional}\right\} \quad (1)$$

Subject to:
Energy balances

$$\sum_{n=1}^{17} d_n - \sum_{i=1}^{17} g_{i,n,(Conventional)} = 0\ \forall\, n, \lambda \quad (1)$$

Transmission constraints which are subject to flow limit (F_{max}) for the line:

$$T_i - \left[\sum_{i=1} PTDF_{1,n} \cdot \sum_n g_{i,n} - \sum_{n=1} PTDF_{1,n} \cdot \sum_n d_n\right] \geq 0\ (\varphi_l^{+})\ \forall\, l \quad (3)$$

$$T_i + \left[\sum_{i=1} PTDF_{1,n} \cdot \sum_n g_{i,n} - \sum_{n=1} PTDF_{1,n} \cdot \sum_n d_n\right] \geq 0\ (\varphi_l^{-}) \forall\, l \quad (4)$$

$$\text{Where } F_L = (Ke - Tz), (Ke - Ug), (Tz - Ug), (Tz - Rw), (Tz - Br), (Rw - Br) \text{ for cross} - \text{border lines and within countries} \quad (5)$$

$$d_n, g_{i,n} \geq 0\ non - \text{negative constraints} \quad (6)$$

$$g_{i,n} \leq g_{i,n,max}\ \forall\, i, n, \widetilde{\omega}_i \quad (7)$$

$$F_L \leq F_{Lmax}\ \forall\, j, \widetilde{\omega}_j, n\ (line\ flow\ constraint) \quad (8)$$

The modelling follows the system of equations (1) to equation (8) on the calculation of nodal pricing under D.C. approximation.

5.2. Clustering Methodology

The evolution of the zonal configuration was based on a grid configuration and the economic scenario. We use the Power Transfer's Distribution Factors (PTDFs) and the resulting Locational Marginal Prices (LMPs). The choice of the PTDFs is to account for the power flow sensitivity to nodal injections and withdrawals, and the modelling is assumed to be in a predefined single-hour snapshot.

The Optimal Power Flow (OPF) algorithm obtains the LMPs based on predefined transmission network data. Since the LMPs contain helpful information on congestion, it is assumed that they can be used to merge LMPs of similar properties heuristically into a zone [37].

A second stage involves clustering the nodes based on the PTDFs, which are as close as possible. In this method, multiple PTDFs are attributed to a specific node and are treated as coordinates of a point; hence the nodes are clustered based on the Euclidean distance. See Appendix 1.

5.2.1. Zonal Pricing

Zonal pricing has elicited many studies, and it remains a subject of discussion. Due to its complexity, the development in this congestion management system has evolved to identify the optimal bidding zones and ensure that it is economically efficient to represent the region's price. In most studies, the assumption has been on the physical observation of the evolution of the LMPs. This method assumes that the LMPs with a similar value will automatically become a zone ('greenfield' approach) [38]. This method, however, is simplistic and does not reflect the economic efficiency of the zonal price [39]. Therefore, there are arguments in favour of using a formula to allocate the zones assuming the endpoints of the congested link, for example, as applied by Stoft [40].

$\sum_{i=0}^{n-x}\begin{bmatrix} n-x \\ i \end{bmatrix}$ Where n represents the connected nodes and x is the assumed zones. In the zonal market, we consider aggregated cross-border capacities between the EAC zones or markets at the clearing time.

The arguments under zonal pricing are whether the prices should evolve naturally or a restriction should be imposed to aggregate or induce the zone's prices to converge. The other argument is whether the restriction should involve the physical country boundaries or the nodal realignment (in integrated cross-border markets) where a contour of different location prices is within a country boundary regardless of the system auction results in various countries. Other methods involve the use of similar PTDF's values as a criterion for partitioning such as by ENTSO, the use of expert knowledge (general split), and the clustering method proposal by Tim [41, 39]. This study suggests that whichever method is applied should have more zones and increase economic efficiency. However, no agreed method has been proven to be working correctly up to now. They are all under trial, and the tools that can efficiently and simultaneously run an optimisation of the market operations and the topology are yet to be developed. Therefore, the identification of the bidding zones is a complex issue. Additionally, all the studies above have been simulated, assuming a perfect competition model.

Several factors are used in arriving at this; the market prices, nodal price differences between the countries, cross-border network congestion and the internal congestion, the power flows, and transmission capacities. Since the EAC market is not yet developed, we rely on the existing calibrated data to determine the bidding zones.

Zonal pricing delineates the nodal pricing such that in each set of networks, the price in that group has a uniform price. One key factor to consider is the ability of the regions/zones to be zoneable.

5.2.2. Clustering Criterion

The criterion employed to group the zones is to simulate the nodal prices within some set of congested lines that yield uniform prices within that zone. This implies that the nodal prices should have one value within a given zone. Zones can be allocated based on optimal nodal price differences or the development of a model that solves to yield a zoning system. In both cases, the clarity of the zoning of boundaries is not clear. Stoft defines zonal boundaries to match the system's congested lines, but the discourse ignores loop flows networks [40]. For simplicity, we adopt the clustering methodology whereby a two-stage approach is adopted; an optimal power flow algorithm is run to obtain the LMP and, since the LMPs contain useful information on congestions, then differences in the LMPs are used heuristically to aggregate the nodes into zones (an indication of Copper-Plate regions). The process involves identifying the LMPs, developing the highest price similarity (slightest price difference) and then calculating the process to develop a new zone. This process ensures that the merging process is effective. This is what is referred to as the dendrogram merge tree. This approach is widely used in the literature [42].

Therefore, to solve the zonal prices, we first simulate the optimal power flow to obtain the LMPs and the PTDF; we then apply the *K*-means clustering methodology to the zone LMPs, thus giving zonal prices:

$$\text{Max}\left\{\sum_{i=1}^{17}\int_0^{q_{1(ke)}^*+q_{2(Tz)}^*+q_{3(Br)}^*+q_{4(Rw)}^*+q_{5(Ug)}^*} P_n^h(q_n^h)dq - \sum_{j=1}^{17}\int_0^{q_{1(ke)}^*+q_{2(Tz)}^*+q_{3(Br)}^*+q_{4(Rw)}^*+q_{5(Ug)}^*} C_n^h\,(q_n^h)qd\right\} \tag{1}$$

Subject to.

Energy balances

$$\sum_{j=1}^{17} q_{jn1.}^h - \sum_{j=1}^{17} d_{jn1.}^h - F_L = 0 \;\ldots\ldots\ldots\ldots\ldots\ldots\;\ldots\ldots.\,\emptyset^{node}(\text{Price in node}) \tag{2}$$

$$F_L \leq F_{ij} \tag{3}$$

Where μ^n is the marginal utilisation costs of the zonal links

$$\sum_{j=1}^{17} q_{p,n}^h = \sum_{j=1}^{17} d_{p,n}^h \ldots\ldots\ldots\ldots\ldots\ldots\forall h \tag{4}$$

Upper and lower bounds of the power flowing through the interconnectors are given as:

$$-F_i \leq \sum PTDF_{1,n}\cdot\left(\sum_n q_{n,p}^h - d_n^h\right) \leq F_i\;(\varphi_l^{h\pm})\;\forall\, h, l \tag{5}$$

Which indicates the system balance and can be expressed as $F_L \leq F_{Lmax}$

$$\sum_n q_{p,n}^h \leq q_{max}^h \; \forall h, p, n \tag{6}$$

($\varphi_l^{h\pm}$) is the congestion rent depending on the direction of flow.

The objective function is represented by line (1), and it is the total consumer benefits (demand curve) minus the total cost of production (supply curves).

(5) Represents the relevant Kirchhoff's loop laws [36].

6. Optimal Bidding Results

In Table 2, a 5-zone configuration has the highest zonal price in Rwanda and Burundi but also has the lowest price of $45/Mwh in the zone straddling in Uganda,Tanzania and part of Burundi. These price formations indicate the level of transmission infrastructure and thus the congestion level.

***Table 2.** Optimal bidding results.*

Bidding Zones Configuration in a country	2 zones Prices ($/Mwh)	3 zones Prices ($/Mwh)	5 zones Prices ($/Mwh)
Kenya	78.06	78.06	121.49
Kenya	78.06	78.06	121.49
Kenya	165.05	110.68	110.68
Kenya	165.05	110.68	110.68
Kenya	165.05	110.68	110.68
Tanzania	78.06	78.06	121.49
Tanzania	78.06	78.06	45.48
Tanzania	165.05	188.35	119.84
Rwanda	165.05	188.35	119.84
Rwanda	165.05	188.35	279.70
Burundi	165.05	188.35	279.70
Burundi	165.05	188.35	279.70
Burundi	78.06	78.06	45.48
Uganda	78.06	78.06	45.48
Uganda	78.06	78.06	45.48
Uganda	165.05	188.35	119.84
Uganda	165.05	188.35	119.84

The three-zone configuration at the EAC gives optimal bidding zones as it yields the highest economic welfare. For example, Figure 2 shows that this configuration yields economic welfare of $1.41million.

***Figure 2.** Bidding zones welfare.*

Unlike previous studies, we do not lock the partitions to a country's physical boundary level. Instead, we allow the zonal prices to evolve under the K means clustering methodology after the initial load flow analysis has been simulated to obtain the nodal prices and the PTDFs.

The selection criterion is based on the zoneable areas, nodal prices evolution and social welfare. However, according to the physical boundary, the zoning has been subjected to many criticisms whereby the assumptions included may not necessarily reflect the value of the zonal prices. Therefore, it is essential to allow the zonal formation to evolve by clustering and the system's congestion level.

The optimal congestion management system remains to be nodal pricing due to higher social welfare and the ability to reflect the marginal cost of electricity production.

Table 3. *Results of a network partition and Zonal Prices for 3 zone configurations.*

Zones	Generators Included	Zonal prices ($/Mwh)	Zonal output (MW)	Welfare ($/Mwh)
Z 1	g1, g2, g6, g7, g13, g14, g15	78.06	6300	1, 083,271
Z2	g3, g4, g5	110.68	1200	129,697
Z3	g8, g9, g10, g11, g12, g16, g17	188.35	553.9	128,820

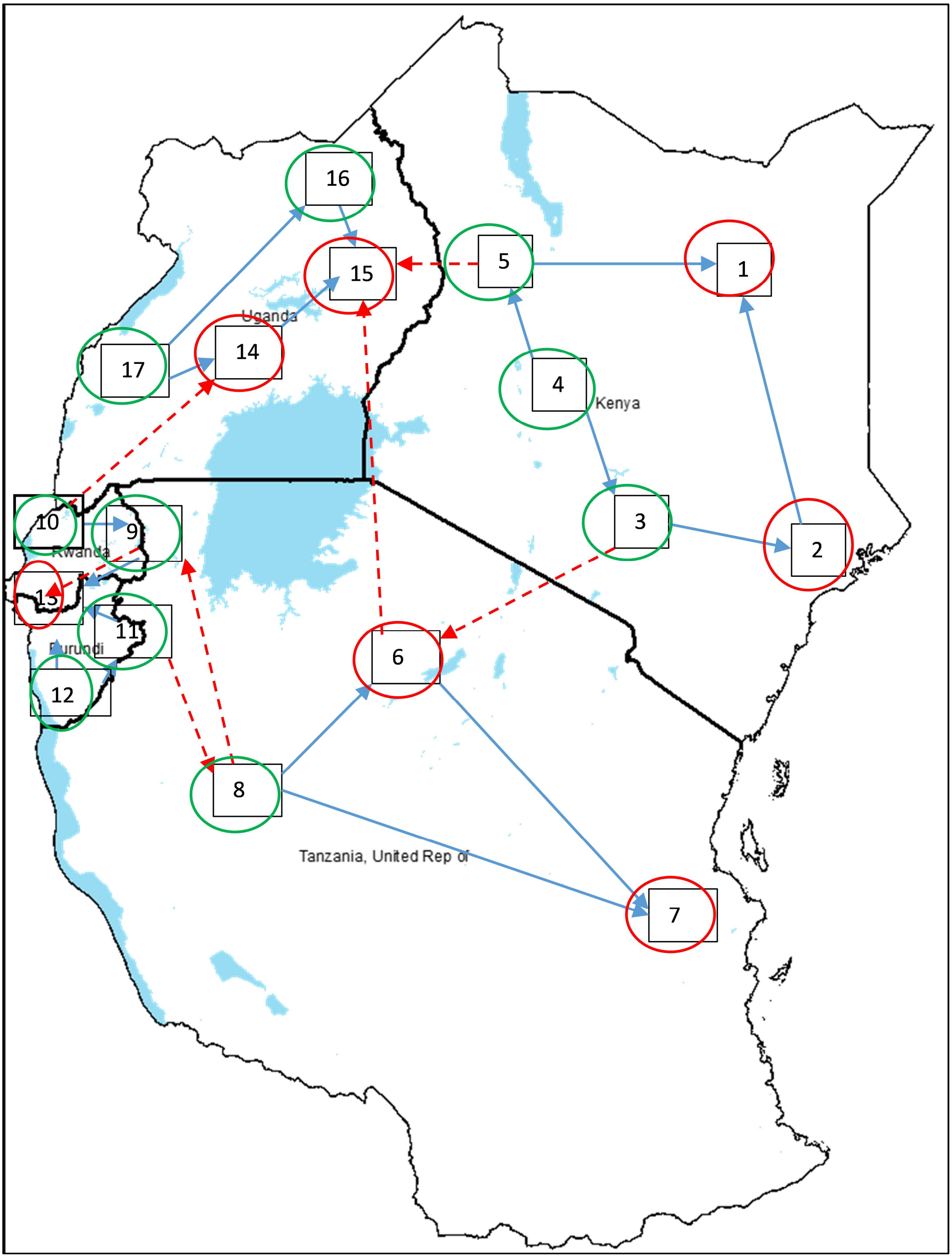

Figure 3. *Optimal zonal topology reduced grid.*

Table 3 give the zonal aggregate output resulting from the partitioning with associated zonal aggregate welfare. Zone one with the lowest zonal price has the highest total economic welfare, while the highest price zone (zone three) has the lowest economic welfare. This implies that the zoning of nodes or regions is beneficial to consumers in the long run, and the liquidity in the electricity market is increased for the generators who intend to invest in the region.

As illustrated in Figure 3, the first zone consists of two nodes in Kenya and two nodes in Tanzania. The second zone straddles across the remaining part of Kenya, while the third zones cover Rwanda and straddle through Tanzania and Burundi and the neighbouring nodes in Uganda. This zone's evolution is critical, especially when considering the congestion management and the power flow within the region. Zone one is the lowest ($78.06/Mwh) zone, while zone three is the most expensive zone ($188.35/Mwh).

Future Work

The research has applied clustering methodology to investigate the feasibility of bidding zones in selected East African Countries. It could be interesting in the future to examine the impact of zonal pricing in short term markets such as intraday and hourly market design in the region when the actual markets are established.

7. Conclusion

There has been significant progress towards creating an integrated electricity market at the EAC by forming the Eastern African Power Pool. However, the EAC member countries power sectors are at different levels of liberalisation, ranging from fully vertically integrated to monopsony. Moreover, neither of the countries has developed an explicit auction mechanism for short term markets, nor are the countries power lines fully interconnected at the borders. Therefore, evaluating the economic welfare resulting from integrating these electricity markets forms the basis for achieving the overarching objective of creating an efficient integrated electricity market for the region. Additionally, integration of the EAC power markets can yield substantial efficiency gains, especially with regard to consumers and the envisaged industrial revolution. The study, applying a clustering method, examines feasible bidding zones. The evolution of these zone types is of critical importance, especially when considering congestion management and power flow within the region.

Through a simulation of zonal wholesale pricing, this paper's economic welfare analysis results indicate that integration in Kenya, Uganda, Tanzania, Rwanda and Burundi that a three-zone configuration would yield the highest welfare gain. Unfortunately, there is no related study in this market to compare our results.

Although integrating these power markets is beneficial, its realisation must be preceded by significant regional institutionalisation and liberalisation, together with deliberate harmonisation of the necessary laws and regulations.

Appendix: Clustering Theory

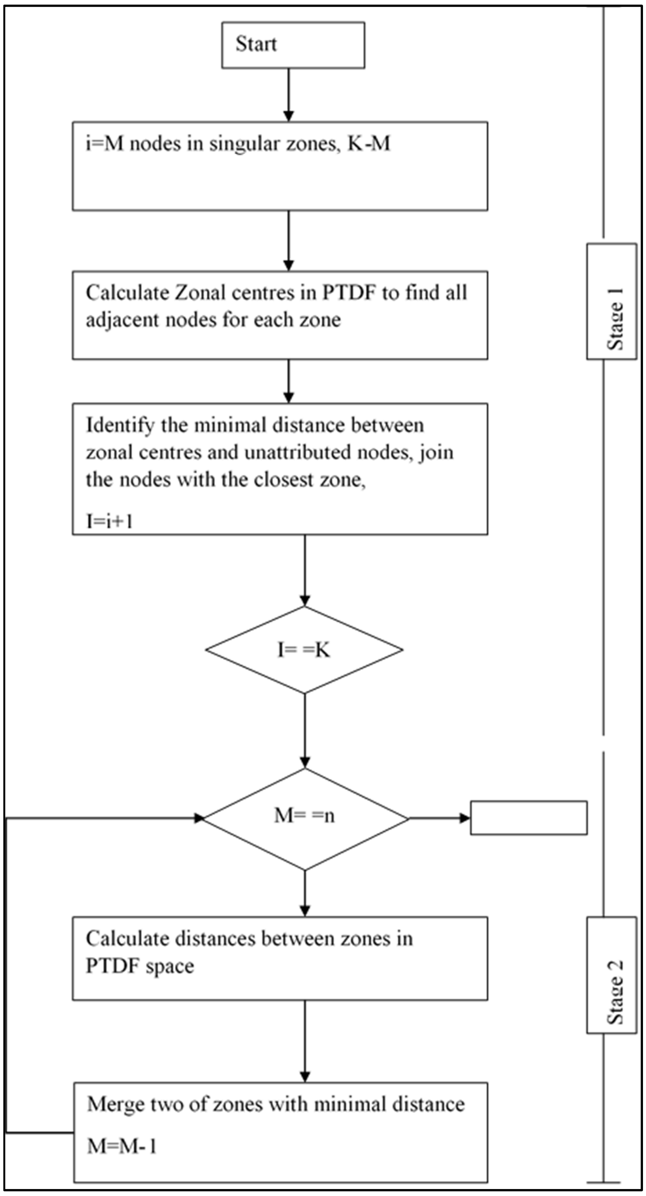

Figure 4. *Flowchart of the PTDF Clustering methodology.*

This partitioning algorithm assumes that the LMP will be clustered into given K clusters.

We have a set of LMP comprising

$$Nodal\ prices\ LMP_i = \{lmp_{i1}, lmp_{i2}, \ldots\ldots lmp_{in}\}$$

We describe in terms of n features where the feature is the node's position and the node number. The next step is to identify the set of clusters that should be used. We assume R clusters comprising of $R = \{R_1, R_2, \ldots\ldots R_k\}$ where the clusters form the partitioning of each LMP.

Each cluster is represented by a cluster centre (denotes the parameter with respect to cluster assignment), which is the PTDF (centroids) attributed to a node.

We follow a criterion to optimise a chosen criterion to find *K* clusters. In our criteria, we apply the within-cluster sum of squares distance given as:

$$\operatorname{argmin}_R \sum_{i=1}^{k} \sum_{lmp \epsilon R_i} ||lmp_i - \mathrm{PTDF}_i||^2 \qquad \text{(A1)}$$

To choose a cluster, we identify the value that will optimise a specific criterion.

We, therefore, find the set of clusters for which A1 is minimised. To achieve this, we adopt the *K* means heuristic algorithm to assist in minimising (A1).

The first step in the *K* means algorithm is randomly selecting the clusters' centres and assigning them as cluster points. The system then assigns each LMP (seeds) to the closest cluster point. Finally, using the new points, we compute the new cluster centre. The process is repeated in the subsequent iteration until a convergence criterion is reached. Consequently, the reassignment of points results in no new value of clusters, or no change of centroids or the minimum decrease in the squared error sum is reached (A1).

The next step is to identify a measure of similarity or distance. In our case, we apply the Euclidean distance, which is given by:

$$\sqrt{\sum_{R=1}^{k} (lmp_{iR} - lmp_{jR})^2}$$

In our case, the PTDF is applied as the centrality measurement whereby the weights are based on average line utilisation for one hour.

The steps are as follows:

The LMPs are obtained by solving an OPF of the EAC power system, considering the line parameters, generator characteristics, load, and marginal cost of supply. The LMP at different nodes reflects the line congestion level; hence, it is useful to apply the clustering approach. The LMP is applied heuristically to aggregate nodes with close resemblance to form a zone. We also understand that the zonal delimitation can change from one hour to the other; we, therefore, assume a single hour period clustering like in Wiszniewska [43]. Ideally, the process involves aggregation according to the distance between any pair of LMPs in the defined PTDF space and the topological adjacency.

Modelling the EAC power system and data

We chose 17 firms out of the 31 major generators because most of the power plants are owned by the same players and are in the same node. Therefore, we merge these plants into one power plant for that node, but we increase the maximum output from that type of power plant. We also assume that one power plant per node and the nodes are represented by the major subsystem classification. See Table 4.

Generators are divided between the nodes in each country according to the country's location. See Table 5 for the firms' names and Table 6 for the generators and nodal calibrated marginal and demand functions.

Table 4. *Strategic players by country.*

Countries	Strategic Companies
Kenya	KenGen-Hydro, KenGen-Geoth, Turkana, Aggreko, Tsavo, Iberafrica, Orpower, Rabai, Thika Power, Triump
Tanzania	TANESCO-Hydro, TANESCO-gas, Songas, IPTL, Symbion, Aggreko, Kilwa, Eskom
Uganda	UEGCL, Bujagali, Aggreko, Jacobsen, KCCL, KML, Electromax, Bugoye
Rwanda	REG-hydro, REG-Dies, REG-Gas
Burundi	REGIDESO

The research considered EAC's five countries which have different national control centres. These control centres have subsystems that are characterised in terms of generation type and large load centres. In this research, we use the subsystems as the nodal points to appropriately capture the region's system. Therefore, the structure of the EAC nodes will be based on the following:

Table 5 displays the system characteristics of the five countries. Kenya has five subsystems, which this paper depicts as NN1 to NN5; similarly, Uganda has four subsystems while Tanzania has three. Due to the small installed capacity size and Burundi and Rwanda's interconnection level, their subsystems are divided into three and two, respectively.

The welfare maximisation problem is implemented in GAMS to solve the expected welfare and prices using a linear programming algorithm.

The modelling under market behaviour involves running the model under perfect completion/price taking. In addition, the market behaviour is tested using two different congestion management techniques involving the nodal and zonal.

Table 5. *Subsystems at the EAC.*

Country	Subsystems	Node
Kenya	Coastal system	NN1
	Nairobi system	NN2
	Western system	NN3
	Seven folks system	NN4
	eastern system	NN5
Uganda	Kampala system	NN6
	Northern (Karuma) system	NN7
	Eastern (Nalubale) system	NN8
Tanzania	South East system	NN9
	Central (Dodoma) system	NN10
	Northern system	NN11
	Western system	NN12
Burundi	Bujumbura system	NN13
	Rwegura system	NN14
Rwanda	South-western Axis	NN15
	Northern Axis	NN16
	Eastern Axis	NN17

Table 6. *EAC Demand and cost curves.*

Inverse Demand Curves			Marginal Cost Curves		
Node	**Intercept**	**Slope**		**Intercept**	**Slope**
NN1	440.00	- 0.21	Gen1	46	0.01
NN2	990.00	- 0.47	Gen2	16	0.001
NN3	550.00	- 0.26	Gen3	83	0.01
NN4	330.00	- 0.16	Gen4	5	0.0005
NN5	330.00	- 0.16	Gen5	83	0.01
NN6	440.00	- 0.28	Gen6	5	0.0005
NN7	220.00	- 0.22	Gen7	16	0.01
NN8	550.00	- 0.33	Gen8	16	0.01
NN9	220.00	- 0.11	Gen9	5	0.0005
NN10	550.00	- 0.28	Gen10	5	0.0005
NN11	440.00	- 0.22	Gen11	83	0.01
NN12	550.00	- 0.33	Gen12	16	0.001
NN13	77.00	- 0.05	Gen13	5	0.0005
NN14	33.00	- 0.02	Gen14	5	0.0005
NN15	55.00	- 0.02	Gen15	5	0.0005
NN16	110.00	- 0.04	Gen16	83	0.01
NN17	66.00	- 0.02	Gen17	83	0.01

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