Modeling the Regional Electricity Network in Southeast Europe

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***Abstract*—The objective of this analysis is to investigate the potential benefits of a regional electricity market in Southeast Europe in 2005. The study models the operation of the electric power systems of seven countries. The primary software tool is the GTMax model, which was used to analyze the operation of individual utility systems, as well as their operation in a regional electricity market. Four typical weeks in different seasons of 2005 are simulated. To capture the variability of hydro inflows and their influence on hydro generation, the analysis is performed for three hydrological conditions: wet, average, and dry. For the regional electricity market scenario, GTMax is used to calculate hourly values of locational marginal prices for all nodes of the regional network and to optimize power transactions among the utility systems. A comparison of operating costs obtained for the two scenarios showed that a regional electricity market provides for significant benefits and cost savings compared to the operation of individual utility systems. Substantial cost savings are achieved in all analyzed periods and under all hydrological conditions.**

***Index Terms*—regional electricity market, interconnections, power transactions, locational marginal prices.**

I. INTRODUCTION

The analysis presented in this paper was performed within the framework of a wider study carried out by a team of experts from Montgomery Watson Harza (MWH) and Argonne National Laboratory (Argonne) under the sponsorship of the U.S. Agency for International Development (USAID). The objective of the study was to examine the role and value of hydro power plants in Southeast Europe, especially within the context of a potential future electricity market in the region. The analysis focused on the power market situation in 2005, which is, according to the Athens Memorandum of Understanding [1], a target year for starting the operation of a regional electricity market for industrial and large (non-residential) consumers.

The study modeled the operation of electric power systems of seven countries in Southeast Europe (Fig. 1). Included were the electric utility systems of Albania, Bosnia and Herzegovina, Bulgaria, Croatia, Macedonia, Romania, and Serbia and Montenegro. Turkey also participated in the project as an observer country but was not modeled. The analysis was performed using the Generation and Transmission Maximization Program (GTMax) developed at Argonne National Laboratory.

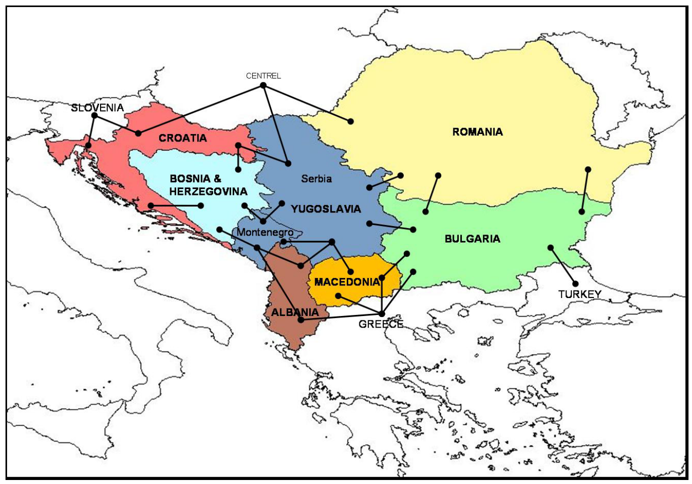

Fig. 1. Regional Interconnected System

As part of the project, the GTMax software was distributed to all participating countries. USAID also sponsored a 3-day introductory training course on the use of the GTMax software for utility experts from the region.

II. METHODOLOGICAL APPROACH

GTMax is Argonne's premier software tool for the detailed analysis of utility systems operations and costs in an open market. With GTMax, utility operators and managers can maximize the value of the electric system taking into account not only its own limited energy and transmission resources but also firm contracts, independent power producer (IPP) agreements, and bulk power transaction opportunities on the spot market. GTMax maximizes net revenues of power systems by finding a solution that increases income while keeping expenses at a minimum. GTMax does this while ensuring that market transactions and system operations are within the physical and institutional limitations of the power system. When multiple systems are simulated, GTMax identifies utilities that can successfully compete on the market by tracking hourly power transactions, locational marginal prices (LMPs), generation costs, and revenues.

The GTMax analysis takes into account the topology of the electric power systems, interconnection transfer capabilities, chronological hourly loads, and the differences in the electricity generation costs in each of the utility systems. GTMax calculates market prices for electricity sales/purchases in different regions (market hubs) of the power network based on the capacity constraints of transmission interties. The model simultaneously optimizes power transactions to minimize overall operating costs in the region.

The analysis was carried out for four typical weeks in 2005 (winter, spring, summer, and autumn). GTMax was used to simulate hourly system operations during the 3rd weeks of January, April, July, and October of 2005. Each utility system was first simulated as operating independently, without the connections with other systems. This was the so-called "individual operation" scenario. Then, all of the utility systems were connected into a regional network, and GTMax was used to simulate the hour-by-hour operation of the regional electricity market ("regional market" scenario).

The hour-by-hour simulation of an entire week (168 consecutive hours) was considered very important in order to capture the operational behavior of hydro and pumped-storage power plants in the region. Most hydro power plants in the region have at least daily regulation capabilities and operate differently during the peak and off-peak hours (e.g., during the day and during the night). Also, in the case of hydro plants with greater storage capabilities there are significant differences between their operation during the weekdays and during the weekends. In order to capture the uncertainty of water inflows and effects of different hydrological situations on the operation of hydro power plants, the analysis was carried out for three hydrological conditions: wet, average, and dry.

Under both scenarios, the utility systems of the participating countries were represented with the generation and transmission facilities that correspond to the expected system configurations in 2005. Similarly, under the regional market scenario, the utility systems were interconnected into a regional network with the existing interconnection lines and with those that are expected to be in operation in 2005. The power transfer capabilities of the interconnection lines were also taken into account during the GTMax simulations of the hourly operations of a regional electricity market. In principle, for the simulation of a regional electricity market, GTMax was used to calculate hourly values of LMPs for all nodes (market hubs) of the regional network and to optimize power transactions among the utility systems. Power transactions were subject to the capacity limits (net transfer capabilities) of the interconnection links among the systems. The resulting LMPs, taking into account the power transactions, were also calculated and reported by the model for each node (or market hub) of the regional network.

III. Regional Network

The topology of the network that was configured in GTMax for the participating countries is shown in Fig. 2. GTMax computes market prices of electricity at various geographical locations within the power systems and at power system interconnections. The market price is assumed to be the marginal cost of delivering energy to a specific location. The companies that generate power are paid the LMP at the point of power injection; that is, the price is dependent on the supply and demand equilibrium. In principle, the LMP price can be less than, equal to, or greater than a generator's average production cost. In this study, it is assumed that generators bid energy blocks into the market at marginal production costs.

Another factor in determining LMPs is the transmission network and its transfer capabilities. In principle, if there is no transmission congestion, power can be transferred to any node of the network and all nodes have approximately the same LMPs. However, in the case of transmission congestion, the transport of power to a particular region in the network may be limited by the transfer capabilities of transmission lines connected to that particular area, thus creating a zone with higher LMPs. Differences in LMPs between two connected regions are used to compute congestion line charges. In this study, the analysis of regional market operation was performed taking into account possible transmission congestion on the interconnection links among the power systems. No internal transmission congestion was considered within individual utility systems.

Besides the existing interconnection lines, the regional transmission network also includes new interconnection links that are expected to be in operation in 2005. These are the following 400-kV transmission lines:

- Chervena Mogila (Bulgaria) –Stip (Macedonia),
- Podgorica (Montenegro)-Tirana/Elbasan (Albania),
- Upgrade of the existing 150-kV line Bitola (Macedonia)-Florina (Greece) to 400 kV,
- Re-connection of the existing 400-kV transmission line Mladost (Serbia) – Ernestinovo (Croatia).

The connections with the outside power systems were modeled in GTMax using spot market nodes. They were used to represent the connections with Slovenia, CENTREL, Greece, and Turkey.

Regarding new generating facilities in 2005, the power systems in the region will mostly rely on generating units that are currently in operation. The only new generating units expected to be commissioned by 2005 are two gas turbines (2 x 150 MW) in Albania and one 174-MW cogeneration plant in Macedonia [2], [3]. On the other hand, two smaller 440-MW nuclear units at the Kozloduy power plant in Bulgaria will be retired (units 1 and 2) and will not operate in 2005.

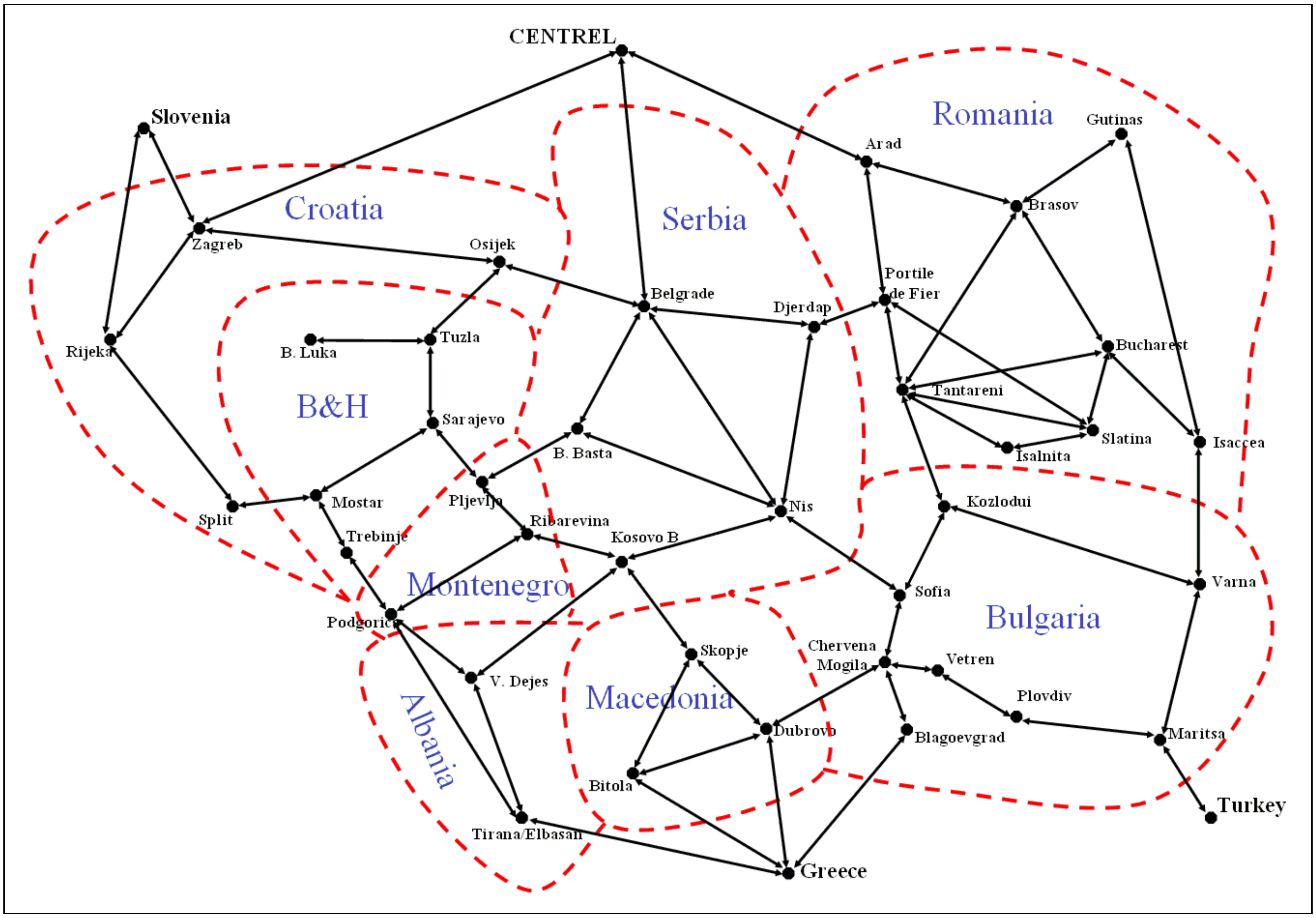

Fig. 2. Simplified GTMax Representation of Regional Network in 2005

IV. Regional Market Analysis

The GTMax model was first used to analyze the operation of individual utility systems and then to analyze the regional market operation. The results obtained for these two scenarios served as a basis to determine the cost differences between the operation of individual systems compared to the regional market operation. These cost differences provide an indication of possible economic benefits of integrating the operation of the power systems in the region. Most benefits and cost savings are expected to be attributable to load diversity, more efficient dispatch of generating units, reduced spinning reserve requirements, and a more reliable system operation.

Under the individual operation scenario, the power systems operate independently and do not trade, sell, or exchange energy or capacity with each other or with the other systems. The results of this scenario reveal electricity generation costs in each of the utilities under the assumption that the systems are operated as isolated entities. Therefore, each system is responsible for satisfying its own electricity demand by means of its own generation resources while maintaining an adequate level of spinning reserve to ensure system reliability.

The regional market scenario allows for power exchanges among the utility systems via the interconnection links. In this scenario, the GTMax model was used to determine the potential for power transactions, optimal energy exchanges, and nodal market prices.

V. Main Results of the Study

The results of the analysis show that the regional electricity market provides significant benefits and operational savings compared to the operation of individual utility systems. Table 1 compares the total weekly operating costs for the regional electricity market and the sum of operating costs of individual utility systems. The results are presented for typical weeks in different seasons of 2005 for three hydrological conditions.

Depending on the season, the total weekly savings for the entire region range from 2.7 to 9.1 million U.S. 2000 dollars. Most of the benefits occur in July under the dry hydrological condition. The smallest savings are found in April under the wet hydrological condition. In principle, the largest cost savings are realized under the dry hydrological condition ($7.5 million average savings in four typical weeks), then under the average hydrological condition (average $6.5 million), and the smallest savings are achieved under the wet hydro condition (average $4.6 million). In terms of percentage savings compared to the operation of individual systems, the results show an average of 11.3% savings under the wet hydrological conditions, 13.9% savings under the average, and 15% savings under the dry hydrological conditions. These are the average costs savings for the four analyzed weeks in different seasons of the year.

TABLE 1: TOTAL OPERATING COSTS FOR TWO SCENARIOS

3rd Week of the Month	Weekly Operating Costs Under Different Hydrological Conditions (U.S.$ '000)		
	Average	Wet	Dry
Operation of Individual Systems			
January	70,290	64,296	77,867
April	32,941	26,665	40,058
July	39,792	33,985	43,478
October	48,100	42,694	53,597
Regional Market Operation			
January	61,200	57,645	71,237
April	28,420	23,965	32,946
July	32,336	28,630	34,385
October	43,162	38,864	46,606
Savings in Operating Costs			
January	9,090	6,651	6,630
April	4,521	2,700	7,112
July	7,456	5,355	9,093
October	4,938	3,830	6,991
Average Cost Savings	6,501	4,634	7,457
Average Cost Savings (%)	13.92	11.30	15.06

The GTMax results also show that the average electricity production costs in the region are significantly lower for the regional market operation compared to the operation of individual utility systems. Fig. 3 provides a comparison of the average electricity production costs in the region in different seasons during the year and under different hydrological conditions. The costs shown in Fig. 3 are the variable costs of electricity generation (e.g., fuel costs and costs of electricity purchases) and do not include fixed costs (e.g., fixed O&M and capital costs). Since the fixed component of the electricity generation cost is identical for both scenarios, Fig. 3 shows that regional electricity market operation results in lower average costs of electricity generation in all analyzed time periods (seasons) and under all hydrological conditions.

GTMax was also used to calculate hourly LMPs in each node of the regional network. A sample illustration of LMPs by country is presented in Fig. 4, which provides a comparison of the average weekly LMPs for the utility systems in the 3rd week of October under average hydrological conditions. In the operation of individual utility systems, LMPs show wide variations from system to system, depending on the plant mix and internal generation costs. On the other hand, in the regional market operation, the LMPs show less variation and tend to equalize the prices of electricity across the region. In the regional electricity market, the variations in LMPs mostly occur when there is transmission congestion in some parts of the network. GTMax simulation results showed that in most cases the regional transmission network in 2005 (including the new transmission links expected to be in operation in 2005) seemed to be capable of transferring the power among the systems, and there was very little variation in LMPs among different utility systems. However, additional load flow, stability, and fault studies should be undertaken to determine the exact needs for transmission system reinforcements in the region. Albania was found to be an area with the weakest connections to the rest of the network, and it was regularly experiencing some transmission congestion. Consequently, the resulting LMPs in Albania in the regional market operation were somewhat higher than in the other systems.

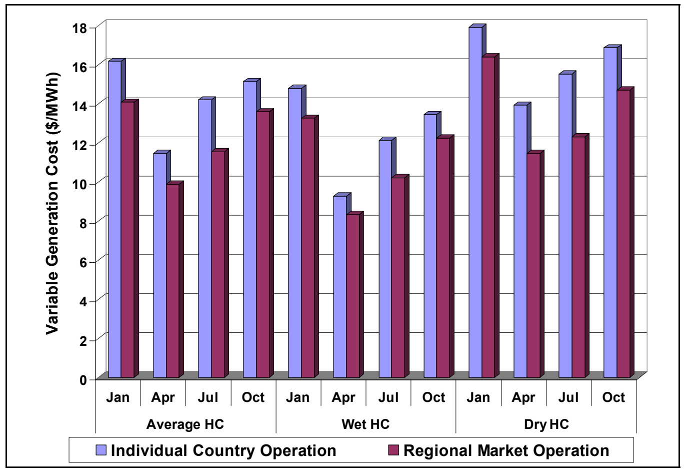

Fig. 3. Comparison of the Average Costs of Electricity Generation in the Region

Energy transactions in the regional electricity market intermittently loaded certain interconnections up to their contractual transfer limits. This was most true for the interconnection links between Bulgaria and Romania, and Yugoslavia (Serbia) and Romania. The reason for this was that, in the regional market operation, Romania was frequently purchasing large quantities of less-expensive power generated in Bulgaria and Serbia. However, this does not increase the LMPs in Romania since all interconnection links were not simultaneously loaded to limit. Therefore, there was always an opportunity to purchase power at a similar price from at least one interconnection point.

In the GTMax simulations, each utility system was required to provide a certain amount of regulation and contingency reserves. The assignments of reserve capacity for regulation (automatic load control - ALC) and for contingency reserves (spinning and non-spinning) to be maintained by individual power plants were optimized by GTMax on an hourly basis. Integrated operation in an interconnected regional electricity market allows for savings in ancillary services, especially in providing the contingency reserves. Compared to the operation of individual systems, all utilities had to provide significantly lower amounts of contingency reserve in the integrated regional operation scenario.

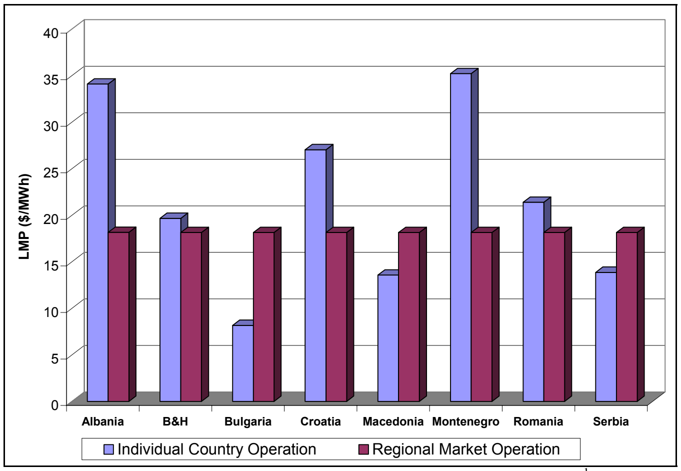

Fig. 4. Average Locational Marginal Prices by Country in the 3rd Week of October 2005 under Average Hydrological Conditions

Hydro and pumped-storage plants provide most of the ancillary services in both the independent and regional market operations. The contribution of thermal power plants to ancillary services is relatively small and even further decreases in the regional market operation. In the operation of individual systems, the contribution of thermal capacity to the total regulation reserve was averaging about 121 MW, or 16.6 percent of the total. This contribution decreased in the regional market operation to an average of 76 MW, or 10.5% of the total. In the case of contingency reserves, the contribution of thermal capacity was already very small (about 1%) in the operation of individual utility systems and decreased to zero in the regional market operation.

VI. Conclusions

The study shows significant benefits of a regional electricity market in Southeast Europe. Practically all of the countries can expect lower electricity generation costs, while some of the utility systems that are suffering shortages of electricity supply would also have more reliable access to power through regional market purchases. In general, the regional market operation would allow for more cost-effective electricity production in the region by increasing the utilization of the most economical generating units (and, on the other hand, decreasing the utilization of the most expensive units), reducing the need for certain ancillary services, and increasing the overall reliability of system operation through better interconnections with other systems.

VII. Acknowledgments

The analysis presented in this paper was performed by a team of experts from Argonne National Laboratory and Montgomery Watson Harza under the sponsorship of the USAID. The authors would also like to acknowledge the efforts of numerous utility experts from Southeast Europe that have participated in this project. Their inputs and valuable insights were greatly appreciated.

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IX. Biographies

Vladimir S. Koritarov graduated in 1982 from the School of Electrical Engineering, University of Belgrade, Yugoslavia. Until 1991 he worked as Senior Power System Planner in the Union of Yugoslav Electric Power Industry. In 1991 he joined Argonne National Laboratory, U.S.A., where he is presently an Energy Systems Engineer in the Center for Energy, Environmental & Economic Systems Analysis. Mr. Koritarov has 21 years of experience in the analysis and modeling of electric and energy systems in domestic and international applications. He specializes in the analysis of power system development options, modeling of hydroelectric and irrigation systems, hydro-thermal coordination, reliability and production cost analysis, marginal cost calculation, risk analysis, and electric sector deregulation and privatization issues.

Thomas D. Veselka is an Energy Systems Engineer in the National and International Studies Section at Argonne National Laboratory. He has provided technical support and managed projects related to electric utility systems and the environment for over 20 years. His work includes extensive hydropower systems analyses in relation to power markets. Mr. Veselka builds optimization and simulation tools and is currently a member of a multi-disciplinary team that is writing an agent-based modeling system that simulates the complex adaptive behavior of participants in a deregulated electricity market.