Power Market Analysis and Potential Revenues of New Transmission Lines in a Deregulated Environment

Vladimir S. Koritarov, Thomas D. Veselka, Bruno Trouille

***Abstract*--This paper describes an approach that was developed to analyze the market potential for power transactions via proposed transmission lines among the electric power utilities of Macedonia, Bulgaria, and Albania. The approach uses an integrated modeling framework consisting of several computer models that estimate the financial and economic benefits of constructing new transmission lines. The integrated model simulates open power markets under several scenarios that include cases with and without the proposed interconnections. The approach estimates power transactions among the three Balkan utility systems and the benefits of coordinated or joint system operations, including short-term power sales agreements.**

***Index Terms*—interconnection, marginal electricity costs, market potential, power transactions.**

I. Introduction

THE main objective of the power market analysis is to determine the potential for power transactions among the electric power systems of Macedonia, Bulgaria, and Albania, as well as the potential for possible electricity exports to Greece. At present, the opportunities to import and export electricity among the three countries are very limited. Currently, there are strong interconnection lines in a general north-south direction, connecting these three utilities with the electric power systems of Serbia and Montenegro in the north and Greece in the south. However, the transmission links in the east-west direction, which connect Macedonia, Bulgaria, and Albania, are rather weak, mainly consisting of 110-kV lines with limited power transfer capabilities. The proposed new transmission lines, 400-kV Dubrovo-Radomir and 220-kV Vrutok-Burrel, would strengthen the east-west interties and significantly increase transfer capabilities among the three utilities. The economic and financial benefits of these proposed lines are a function of both energy transaction volumes and the cost savings that can be attributed to these transactions. These benefits can be compared with the cost of building the lines.

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II. Methodological Approach

An integrated modeling framework consisting of several computer models was developed for the power market analysis. It is comprised of the ELECTRIC/WASP module of the Energy and Power Evaluation Program (ENPEP), the PC-VALORAGUA (Value of Water) model, the Generation and Transmission Maximization (GTMax) model, and the Project Finance Model. An illustration of the integrated modeling framework and information flows among the major components is shown in Fig. 1. The economic and financial analyses focused on the power market situation in two key years: 2005 and 2010.

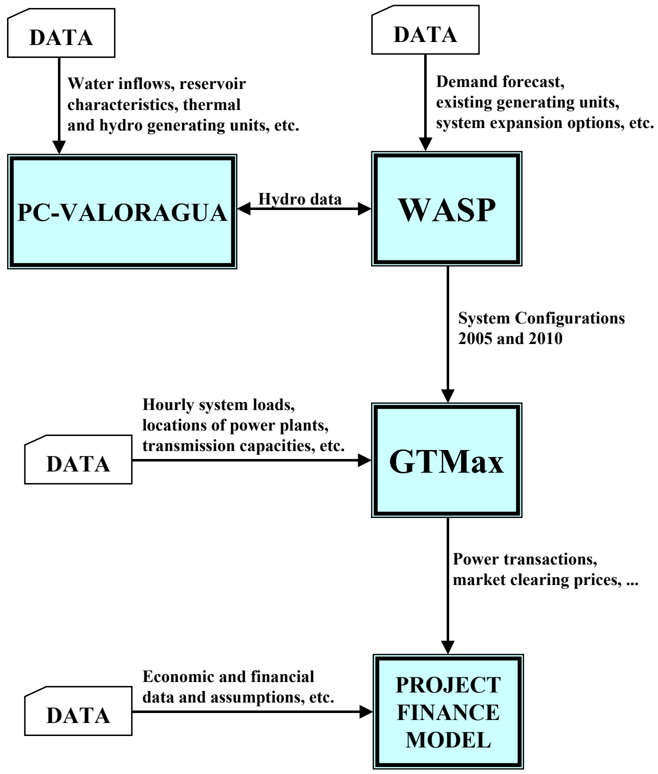

Fig. 1. Integrated Modeling Framework

To project system configurations in 2005 and 2010, the ELECTRIC/WASP and PC-VALORAGUA models were utilized to develop least-cost expansion plans for the electric power systems of Macedonia, Bulgaria, and Albania. The ELECTRIC/WASP module of ENPEP is an optimization model for examining medium to long-term capacity development options for electrical generating systems. The objective of WASP is to determine the optimal pattern of system expansion that would meet the system demand over a given study period, while satisfying all user-specified reliability requirements and other limitations and constraints. For a more rigorous examination of optimal expansion paths of mixed hydro-thermal systems, the WASP model is used in combination with the PC-VALORAGUA model. This model has an enhanced representation of hydropower plants and their operation in the electric power system. PC-VALORAGUA is a hydro-thermal coordination model that simulates the operation of all types of hydro power plants (including the pumped-storage plants) and determines an optimal policy for the management of hydro reservoirs. In addition, it considers the requirements of irrigation reservoirs and optimizes the operation of hydro cascades.

The WASP/VALORAGUA methodology was utilized to develop expansion plans for two main scenarios:

(1) Expansion of isolated utility systems, and
(2) Expansion of interconnected systems.

The purpose of these two scenarios is to determine the most likely plant mix in the three utilities in 2005 and 2010 and to calculate the cost difference between the operation of isolated systems compared with the operation of the interconnected systems. Cost differences provide an indication of the maximum interconnection benefits. Most benefits and cost savings achieved through the interconnected operation are attributed to load diversity, lower capacity additions, reduced spinning reserve requirements, a more efficient dispatch, and a more reliable system operation.

The WASP/VALORAGUA expansion results were then transferred to the GTMax model. The model simulated the hourly dispatch of power plants and the potential for power transactions among the three utility systems. Marginal electricity costs for energy exports to Greece were also determined.

The GTMax model was developed by Argonne National Laboratory with the objective of simulating the operation of interconnected power systems and power transactions in an open power market. 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 three utility systems. GTMax calculates market prices for electricity sales/purchases in different regions (zones) of the power network based on the capacity constraints of transmission interties. When computing market prices, it is assumed that they are based on marginal production costs (short-run marginal costs of electricity in different nodes of the network). The model simultaneously optimizes power transactions to minimize overall operating costs.

The GTMax analysis was carried out for system configurations in 2005 and 2010 for two basic scenarios:

(1) Without new interconnection lines (isolated systems), and
(2) With the new interconnection lines, Dubrovo-Radomir and Vrutok-Burrel.

In the first scenario, the three power systems (i.e., Albania, Bulgaria, and Macedonia) operate independently and do not trade, sell, or exchange energy or capacity with each other or with the Greek power system. 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. The second scenario allows for power exchanges among the three utility systems via the proposed interconnection lines. In this scenario, the GTMax model was used to determine the potential for power transactions, optimal energy exchanges, and nodal market prices.

The results of the GTMax model were then transferred to the Project Finance Model to determine the economic and financial viability of the proposed new interconnection lines.

III. Expansion Studies

The expansion analysis for the electric power system of Macedonia was carried out using the WASP/VALORAGUA methodology, while expansion analyses for the power systems of Bulgaria and Albania were conducted using the WASP model. The analyses of expansion options for these three electric power systems were carried out for two main scenarios, that is, expansion of isolated utility systems and expansion of interconnected systems.

A. Expansion of Isolated Utility Systems

In the isolated systems scenario, the expansion analysis was conducted separately for each of the three isolated systems. Each power system was considered to be completely independent, and the expansion analysis was carried out with the assumption that systems would maintain self-sufficiency in supplying their own electrical demand over the study period.

Expansion options and candidate generating technologies included in the analysis were based on both local energy resources and future potential fuel imports. The sizes of candidate generating units were selected in accordance with the capacity expansion requirements of each power system. Although expansion analyses for the three power systems were carried out independently, most key assumptions were standardized across all expansion analyses. For example, input values for system reliability criteria, including reserve margins, energy-not-served cost, and loss-of-load probability (LOLP), were identical for all analyses over the entire study period. Also, values for some key economic parameters and criteria (e.g., present worth date, discount rates, depreciation methods, fuel price projections, etc.) were the same in all analyses.

The expansion analyses for isolated systems were carried out with three main objectives:

- Analyze future expansion options for each of the three isolated systems;
- Calculate total system expansion and operating cost over the 2000-2020 study period for each power system; and
- Determine optimal system configurations (plant mix) in 2005 and 2010 for each utility system.

The system configurations in 2005 and 2010 obtained from the WASP/VALORAGUA analyses were then transferred to the GTMax model to determine potential opportunities for power transactions among the three utilities.

B. Expansion of Interconnected Systems

The expansion analysis of interconnected systems was carried out for the two main scenarios. In the first scenario, all three utilities follow their respective expansion programs obtained from the WASP isolated systems runs. This analysis is referred to as a *fixed expansion program*. Although the expansion plans were not jointly planned, all three utilities were assumed to operate as a single tightly interconnected power pool. The analysis was conducted without transmission constraints (no congestion). It was also assumed that generating units in all three systems were jointly dispatched to satisfy the combined system loads. Identical to the isolated systems expansion analyses, the dispatch of generating units is based on a pure economic loading order, adjusted for the spinning reserve requirements.

The system operation results for the fixed expansion program for 2005 and 2010 were then compared with the respective operation results obtained from the expansion plans of the isolated systems. In the isolated system runs, loads in a system could only be satisfied by the dispatch of units in that system. Therefore, the cost difference between these two model runs quantifies the potential benefits of a joint dispatch for the combined systems and provides an indication of the maximum interconnection benefits. These cost differences are attributed to savings in fuel and variable operation and maintenance (O&M) costs – expansion costs are identical.

The present value of the total cost savings over the study period amounted to about $891 million. This value was obtained by comparing the total cost over the study period for the fixed expansion program to the sum of respective total costs for three isolated system simulations. It should be noted that not all of the cost savings could be directly attributed to the new interconnection lines Dubrovo-Radomir and Vrutok-Burrel. The portion of cost savings that can be attributed to the two proposed lines was calculated later with GTMax.

In the second scenario, it was assumed that the three utilities would not only be dispatched as a single power pool, but that the utilities would also jointly optimize capacity additions on a regional basis. In this case, the least-cost expansion analysis was optimized for the combined system without regard to the individual expansion plans that were obtained for the isolated utility systems. For consistency, the expansion options that were considered in this case were based on the candidate technologies used in the isolated systems analyses; their geographical locations were also taken into account.

This second scenario not only has cost savings from a joint dispatch, but also has additional savings from lower capital investment costs in new units. Since the sum of non-coincidental peak loads is larger than the coincidental peak, the combined system needs less new capacity over the study period as compared with the development of three isolated systems. Other factors, such as lower spinning reserve requirements for the joint system and the transfer of excess capacity in one system to another, also reduce the total capacity expansion requirement. Further, the relatively large size of the combined system allows for the selection of larger unit additions that are generally more efficient and less expensive in terms of investment costs per kW of installed capacity.

The expansion results for the interconnected systems scenario were compared with the respective results obtained for the expansion of isolated systems. WASP/VALORAGUA results for the optimized expansions showed a 1,086 MW reduction in new capacity additions over the period until 2020. The present value of the total cost savings over the period 2000-2020 amounted to about $1,372 million. A comparison of total system investment and operating costs over the study for the three different cases is illustrated in Fig. 2. All costs are expressed in constant U.S. dollars as of the beginning of 1999.

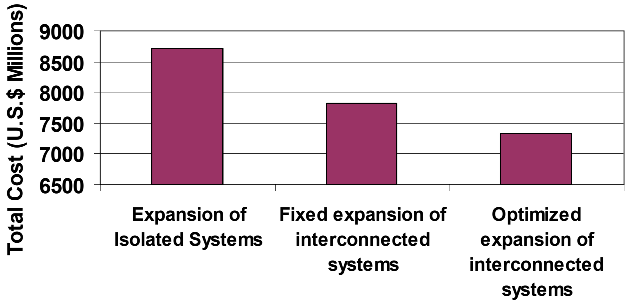

Fig. 2. Comparison of Total Expansion Costs over the Period 2000-2020 for Three Scenarios

IV. Power Market Analysis

The system configurations of generating units projected to operate in Albania, Bulgaria, and Macedonia in 2005 and 2010, as determined by the WASP/VALORAGUA expansion studies, were then passed on to the GTMax model to simulate their hourly operations and the market potential for power transactions. GTMax estimates the hourly dispatch of thermal and hydropower resources and determines the set of units that are committed to be operational during simulated weeks. The model also estimates hourly market prices of electricity on a regional basis. For this analysis, the model was run for four weekly periods that are representative of the seasons. These include the third weeks of the following months: January (winter), April (spring), July (summer), and October (autumn). System operations were simulated for two snapshot years, 2005 and 2010, and under three hydrological conditions.

GTMax was used to estimate the operations of three Balkan utilities under three scenarios. Under the first scenario, Isolated Systems, it is assumed that the three power systems operate independently and that the countries neither exchange energy nor engage in the buying and selling of electricity with other systems. 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.

Under the second scenario, Interconnected Systems, a transmission line connects the Bulgarian and Macedonian systems with an operational transfer capability of up to 1,000 MW. A second line connects Albania and Macedonia with a transfer capability of 250 MW. The GTMax model computes the amount of energy that is purchased and sold via these transmission lines on an hourly basis under the assumption that all transactions are under short-term non-firm agreements. These agreements are energy-only transactions with no firm capacity component. Unit commitments under this scenario are identical to the Isolated Systems Scenario under the assumption that each individual system would be self-sufficient in the event that a non-firm transaction with another country is interrupted.

The third scenario, Coordinated Systems, is identical to the second scenario, except that there is short-term (weekly) coordinated planning among operators in the three systems. This entails determining unit commitments based on a single integrated system or power pool. Additional benefits can be gained by placing units that are expensive to operate on cold standby and allowing less expensive units to operate at higher capacity factors. In addition, by taking advantage of load diversity, more units can be placed on cold standby than under the first and second scenarios. Under the Coordinated Systems scenario, it is assumed that there is a fairly high level of communication among the systems and that energy transactions are very reliable.

The topology of the network that is configured in GTMax for the three Balkan countries is shown in Fig. 3. GTMax computes market prices of electricity at various geographical locations within each of the three power systems and at power system interconnections. The market price is assumed to be the marginal cost of delivering energy to a specific location. All energy transferred through an interconnection line is charged at the same market price. Total purchase expenses and sales revenues are set equal to the market price times the amount of energy sold.

Since each of the three systems relies on hydropower plants to serve a significant portion of its load, the GTMax model was run under three different hydrological conditions: dry, normal, and wet. Expected expenditures for serving loads are based on the average costs for the three conditions weighted by the probability of occurrence.

Fig. 4 shows GTMax average net operating costs in 2005 and 2010. The weighted average annual cost savings increases from \$21.2 million in 2005 to \$23.3 million in 2010 under the Interconnected Scenario and increases from \$41.7 million in 2005 to \$55.3 million in 2010 under the Coordinated Scenario.

Costs vary significantly around these averages as a function of hydrological condition. Generally, costs under all scenarios are higher under dry hydrological conditions. The cost variation in this case is the greatest for Albania since it normally relies on inexpensive hydrogeneration to satisfy most of its electricity demands. However, under the dry hydrological conditions, the Albanian system also needs the generation from expensive peaking units. On the other hand, when unit commitment schedules are not jointly planned but the systems are connected, net operating costs for Albania in 2005 under wet hydrological conditions are negative. This occurs because the generation costs are minimal and the country has large amounts of excess hydropower to sell to Macedonia. However, net costs in Albania under the Coordinated Systems Scenario during wet periods are positive since cold standbys are optimized over the three combined systems and most thermal units in the country do not operate. Energy purchase levels increase, and the price becomes expensive, as the Albania-Macedonia line is at maximum transfer capability most of the time.

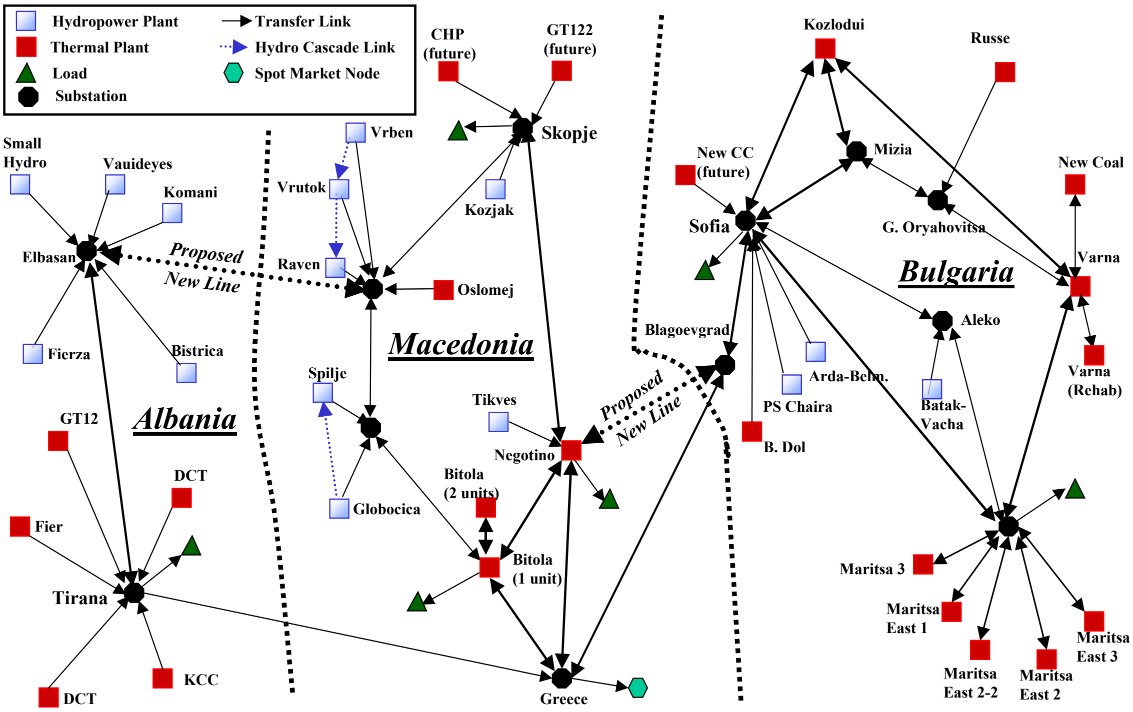

Fig. 3. GTMax Representation of the Interconnected Systems Albania-Macedonia-Bulgaria

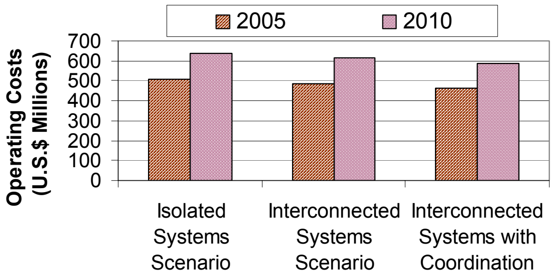

Fig. 4. Comparison of Net Operating Costs in 2005 and 2010 for the Weighted Average Hydrological Condition

Of the three Balkan countries analyzed, Bulgaria's net costs have the lowest level of cost variation. The hydropower reliance level is relatively low in Bulgaria, and it has a large thermal capability with low operational costs.

As an illustration, Fig. 5 shows the projected power transactions among the three utility systems during a typical week in autumn 2005. The results are shown for the wet hydrological condition under the Coordinated Systems Scenario. Fig. 6 illustrates the corresponding market prices (based on marginal electricity costs) for power transfers among the three utilities during that same week.

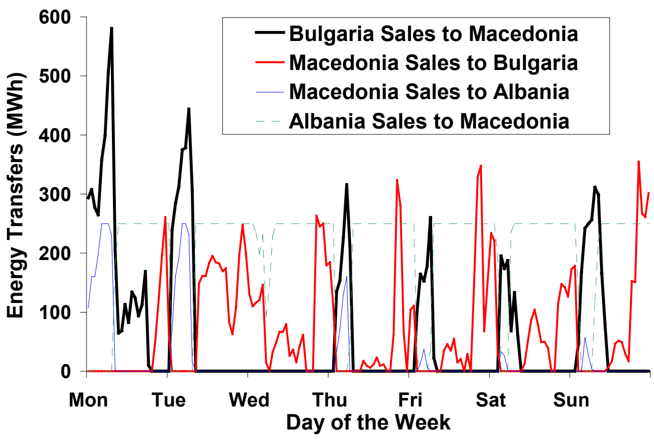

Fig. 5. Expected Power Transfers During a Typical Week in Autumn 2005 under a Wet Hydrological Condition

V. Financial Analysis

A pro forma financial model was prepared to assess the financial viability of the project. The model determined the break-even revenues required to cover debt service and to meet equity return requirements, based on the specified transmission line rating, capital and operating costs, and financial costs and structure. A base case was developed, assuming 75% debt financing and 25% equity. The cost of debt was estimated using a 10-year Treasury rate of 5.75%, plus 375 basis points for country and project risk, for a total borrowing rate of 9.50%. Multiple scenarios were evaluated to assess the sensitivity of calculated transmission prices due to changes in the major variables used in the model.

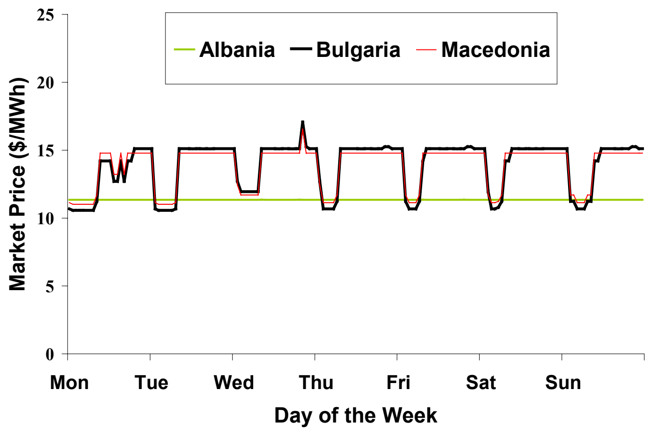

Fig. 6. Market Prices during a Typical Week in Autumn 2005 under a Wet Hydrological Condition

For the Macedonia-Bulgaria transmission line project, the total investment cost was estimated at $80.9 million. Annual O&M, overhead and insurance costs were estimated at $1.15 million. Based on these costs and the financial assumptions, an annual revenue requirement of $14.8 million would be required to provide an equity internal rate of return (IRR) of 18%. This is equivalent to a levelized price of $6.92/MWh, assuming a 25% utilization factor or an annual energy transfer of 2,145 GWh.

For the Macedonia-Albania transmission line project, the total investment cost was estimated at $19.8 million. Annual O&M, overhead and insurance costs were estimated at $0.35 million. Based on these costs and the financial assumptions, an annual revenue requirement of $3.7 million would be required to provide an equity IRR of 18%. This is equivalent to a levelized price of $6.91/MWh, assuming a 25% utilization factor or an annual energy transfer of 538 GWh.

The financial model was also used to test the sensitivity of the indicated pricing to changes in several of the key variables. For each scenario, the model was run to calculate the transmission price that would yield the target IRR.

VI. Conclusions

This paper describes a methodology for analyzing system expansion, power plant operations, and energy transfers at various levels of granularity using a concise and consistent approach. This allows analysts to study systems from a long-term perspective while preserving the hourly level of detail that is required under actual system operations. The analysis shows that benefits increase as a function of joint system cooperation. Levels of joint system cooperation include short-term energy transactions, coordinated unit commitment scheduling, and multi-system joint capacity expansion planning.

The results of the analysis show that the economic benefits of planning and operating the three electric power systems in an integrated and deregulated regional market are enormous, varying between $0.9 and $1.4 billion over the next 20 years. Required investments in transmission interconnections, regional SCADA and communications, and joint planning and dispatch centers are expected to be a third of this amount.

Additional studies are recommended to expand the present study of three countries to the entire Balkan region. As the region becomes re-synchronized with the UCTE, it is expected that the proposed interconnections would allow much greater power transactions among the various countries.

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VIII. 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 and is presently an Energy Systems Engineer in the Center for Energy, Environmental & Economic Systems Analysis. Mr. Koritarov has 20 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 as related 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.

Bruno Trouille graduated in 1975 from l'Institut Catholique des Arts et Métiers (Master of Science in Civil and Mechanical Engineering) in France. He also obtained in 1978 a Master of Science in Industrial Relations from Loyola University, Chicago. Mr. Trouille has worked with MWH since 1978. He serves as a Senior Project Manager or lead economic and financial analyst on power projects, power system expansion studies, regional market analyses, and project financing. He is a member of several professional societies.