# REPORT

# ON

# SOUTH EAST EUROPE MARKET MONITORING

## FOR THE PERIOD

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## EXECUTIVE SUMMARY OF MAIN FINDINGS

This is the fourth quarterly report providing an account of market monitoring activities under the South East Europe (SEE) Market Monitoring Pilot Plan initiated by the United States Agency for International Development (USAID) and the National Association of Regulatory Utility Commissioners (NARUC). This report covers the period September to November 2007.

The report is in three main parts: (1) monitoring of overall market indicators; (2) monitoring of interconnection capacity; and (3) development of a simulated network model.

### *Overall Market Indicators*

We monitor regional wholesale prices and regional congestion in order to provide an overview of market conditions and outcomes. We compare day-ahead spot market prices from Austria and Romania in order to track general price levels as well as to assess regional spot market efficiency. We find a persistent divergence of prices between the two markets. Romanian prices tended to be higher than Austrian prices during the past summer, but the opposite relationship prevailed during the fall. This suggests either binding transmission constraints that prevent the arbitrage of prices or a poorly functioning wholesale spot market. We continue to monitor this situation to further explain it and identify potential changes to address it.

We monitor congestion over both the planning horizon congestion (week-ahead ahead or longer) and over the operating horizon (day-ahead or shorter). Planning horizon congestion occurs when Available Transmission Capacity (ATC) on an interconnection is zero. This occurs relatively frequently, especially in the southwest part of the region. Operating horizon congestion occurs when a TSO takes actions to curtail transactions in the day-ahead or shorter time-frame in accordance with UCTE congestion management procedures. Surprisingly, this type of congestion rarely arises; for instance, it was not reported as occurring at all during the September to November period.

### *Monitoring of Interconnection Capacity*

We monitor the market for cross-border capacity by comparing the allocation of interconnection capacity to the actual usage of that capacity. We introduce new dimensions to our analysis by

considering estimates of physical flows associated with cross-border capacity values produced in the Capacity Assessment. More precisely, we estimate the physical flow that would be associated with Already Allocated Capacity (AAC) values, as well as the physical limit on interconnections that is implicit in the NTC values. These estimated values allow a more direct assessment of how the real-time physical flows compare to the capacity requirements that are established in the month-ahead capacity allocation process. Such a comparison provides a market monitoring screen that can detect potential market issues associated with cross-border trading.

Our analysis estimates the maximum potential physical flow from cross-border capacity reservations (i.e., from AAC). This physical flow arises both from the direct reservation between the two counterparties on the interconnection, as well as potential physical flows from transactions among other TSOs (i.e., loopflow). The analysis reveals the amount of physical capacity that is reserved by the counterparties to the interconnection, versus the physical capacity that potentially would be occupied by loopflow from reservations on other interconnections. We also estimate the physical capacity that is available for cross-border transactions and compare this to the maximum potential physical flows from all AAC (both the direct AAC from the counterparties and the AAC from all other regional interconnections). Our analysis illustrates that in many instances, the interconnection is over-reserved because the process for establishing capacity rights on the interconnection does not coordinate loopflow effectively. This shortcoming is a standard problem in a contract-path-based transmission reservation process like the one used in the SEE region.

We also estimate the physical limit on each interconnection, which enables us to monitor the physical flow related to the physical limit. This provides a way of identifying locations where larger NTC could be particularly beneficial and a way of detecting potential misuse. It also allows us to compare the actual physical flows to the estimated flows from the AAC, providing a screen that may indicate unscheduled uses of the system. Other means of evaluating scheduling issues are limited because we do not currently have access to scheduling data.

We analyzed 20 interconnections.[1] Eight of these 20 interconnections were relatively inactive. The interconnections exhibited minimal or no reservations and little or no physical flow occurred in real-time. These relatively inactive interconnections are: Albania to Montenegro; Bulgaria to Romania; Bosnia & Herzegovina to Serbia; Croatia to Serbia; Macedonia to Serbia; Montenegro to Bosnia & Herzegovina; Montenegro to Serbia; and Serbia to Romania. These interconnections tend to be ones that serve power transactions in the west to east direction, which is against the predominant flow in the region. Our screening did not detect potential market or efficiency problems associated with any of these interconnections.

The other twelve interconnections were relatively active. Reservations and physical flows were significant. On five of these interconnections, ATC was non-zero and real-time physical flows were consistent with the reservations on the interconnections. These are Albania to Serbia; Bosnia & Herzegovina to Montenegro; Croatia to Bosnia & Herzegovina; Montenegro to Albania; and Serbia to Montenegro. We do not find that the reservation or usage patterns on these interconnections raise competitive issues.

Of the remaining seven interconnections, there were results that raise potential concerns. On the Serbia-to-Albania interconnection, significant physical capacity was available that was unused while zero ATC was posted, which indicates that ATC may have been underestimated. On the other six interconnections, either the (1) ATC was frequently zero or (2) physical flows were significantly higher than what would be expected given the reserved capacity. These interconnections include Bosnia & Herzegovina to Croatia; Romanian to Bulgaria; Romania to Serbia; Serbia to Bosnia & Herzegovina; Serbia to Croatia; and Serbia to Macedonia. The potential concerns on these interconnections are of two types. First, the excess flow may be the result of unscheduled uses of the system or loop flow volume that is not reflected in the base case data. Second, because in some cases ATC is zero and flow is significant, careful analysis of the Capacity Assessment may be warranted to ensure NTC and ATC values are being maximized in accordance with accepted procedures. While these results may be explained by operating and

[1] The two interconnections between Bulgaria and Serbia were not analyzed due to the lack of physical flow data from both of these entities.

market conditions, they may also indicate potential efficiency issues or competitive concerns that warrant further investigation.

ATC was frequently zero and physical flows were significantly higher than what reasonable would be expected given the reserved capacity. These interconnections include Bosnia & Herzegovina to Croatia; Romanian to Bulgaria; Romania to Serbia; Serbia to Bosnia & Herzegovina; Serbia to Croatia; and Serbia to Macedonia. The potential concerns on these interconnections are of two types. First, the excess flow may be the result of unscheduled uses of the system. Second, because ATC is zero and flow is significant, careful analysis of the Capacity Assessment may be warranted to ensure NTC and ATC values are being maximized. While these results may be explained by operating and market conditions, they may also indicate potential efficiency issues or competitive concerns that warrant further investigation.

***SEE Regional Network Model***

REKK has been developing a network model of the South East Europe region which combines a model of generation dispatch with a transmission network representation. The motivation for developing this model is to study a competitive benchmark for the purpose of future monitoring.

The following are the key observations from the modeling:

- Both Romania and Bulgaria are low-cost net exporters into the SEE region with relatively low internal market prices and congested borders. Reasonable changes in interconnection capacity towards the rest of the SEE region do not significantly affect prices in these two markets, as they are largely determined by internal economic forces.
- Market prices in much of the central and western part of the SEE region are closely connected to the outside (“northwestern”) prices prevailing in the neighboring countries under a wide variety of conditions. Net exports are not unidirectional, but depend on the level of Hungarian and Slovenian prices.
- Within the SEE region, a high-price congested sub-region consisting of Albania and Macedonia appears under certain conditions, due to the insufficient internal generation capacity and relatively weak interconnections into these markets.

# I. OVERVIEW

The Market Monitoring Pilot Plan was originated at the Eighth Athens Forum in June 2006 when the Forum invited USAID to move forward on its proposal for market monitoring. Accordingly, a Market Monitoring Pilot Plan was conceived and presented to transmission system operators (TSOs) and other stakeholders at an October 2006 workshop in Brussels. The primary objective of the Brussels workshop was to develop a collaborative relationship with the TSOs for the purpose of initiating and sustaining the Pilot Plan. In accordance with the recommendations solicited from TSOs and others at the workshop, a market monitoring plan was established and market monitoring started in December 2006.[2] Since the inception of the plan, we have collected and analyzed market data, published regular quarterly reports, and presented our findings to the Athens Forum.[3]

## A. Objectives of the Pilot Plan

Consistent with the Treaty establishing the Energy Community, which entered into force in July 2006,[4] the overall objective of the Pilot Plan is to advance the competitive structure of electricity markets in South East Europe. To this end, the Pilot Plan seeks to enhance market transparency, facilitate open-access, and detect potential market failure. The Pilot Plan seeks ways to provide benefits to Transmission System Operators ("TSOs") consistent with this objective. The monitoring reports, for example, provide the TSOs with a convenient source of data for analyzing regional market conditions and events.[5] The Pilot Plan also addresses regional market

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2 The Market Monitoring Plan is located on the SEE Market monitoring website: http://www.naruc.org/see_monitoring/docs/SEE_Market_Monitoring_Plan_DRAFT_12_01_06_Web.pdf

3 USAID, in conjunction with NARUC, assembled a team of consultants to develop the Pilot Plan. The consulting team includes Dr. Peter Kaderjak of the Regional Energy Policy Center (REKK) at Corvinus University in Budapest, Dr. David Newbery of the Energy Policy Research Group (EPRG) at Cambridge University in England, and Dr. Robert Sinclair of Potomac Economics in Fairfax, Virginia.

4 It is widely recognized that market monitoring can promote market competition by creating market transparency, facilitating open-access, and detecting market power and other market abuses. See, *e.g.*, Newbery, D., and R. Green, "Review of the Monitoring of Market Power – The Possible Roles of TSOs in Monitoring for Market Power in Congested Transmission Systems", Report to the European Electricity Transmission System Operators, 2004.

5 Even though the key data comes from the TSOs themselves, combining the data to develop regional analyses can assist the TSOs in their own market analyses.

issues that can assist the TSOs in developing effective competition polices. As in previous reports, we emphasize the collaborative nature of this project and invite comments and input at any stage of the Pilot Plan.

## B. Summary of Report

This report presents our monitoring activities for the period September – November 2007. It is our fourth report under the Pilot Plan. This report continues the analyses from previous reports as well as provides updates to our ongoing analysis and data collection.

### 1. Data Procurement

Our data collection activities are facilitated through contact with the individual participants. There are nine participants in the Pilot Plan. This includes the United Nations Mission (UNMIK) in Kosovo who is a signatory to the Energy Treaty and is involved, like the other participants, by providing data for monitoring. Overall we are satisfied with the level of cooperation from the participants. The data was provided in a useful format and aside from a few claims of confidentiality of certain data, especially with respect to generator data, the objections did not prevent us from moving forward on our analyses. The main exception to otherwise broad participation was Bulgaria. The TSO in Bulgaria has not responded to our requests for data since the inception of the Pilot Plan. Moreover, cross-border transmission capacity data which is required to be made public under European Union regulations was not provided by Bulgaria.

### 2. Network Congestion

Our analysis of network congestion focuses on two indicators of congestion. The first indicator relates to the availability of cross-border transmission capacity through the “capacity assessment”, which is a procedure for calculating Net Transmission Capability (NTC) and Available Transmission Capacity (ATC). When ATC is zero or close to zero, this indicates

limits on additional market activity and potential market failure.[6] The second indicator is the invoking of congestion management procedures that may lead to curtailment of transactions.

*ATC Values*. NTC and ATC calculations are coordinated among TSOs in accordance with guidelines established by the UCTE and endorsed by the European Transmission System Operators (ETSO).[7] There are 22 interconnections[8] linking the Pilot Plan participants. We collected ATC values on eighteen of them.[9] On five paths ATC was zero in one or more of the months during the September-November period. Otherwise capacity was generally available. However, large regional trades would be limited because on many paths (nine out of eighteen) capacity was below 50 MW in one or more of the months. We have not gathered the data at this stage of the monitoring plan that would enable us to indicate whether such transfers were abandoned as a result of insufficient ATC.

*Congestion Management Procedures*. Congestion management procedures are designed to ensure reliable use of the transmission network when network transactions cannot be securely accommodated. Congestion management becomes a market monitoring issue in instances when transactions have to be curtailed or otherwise reduced in order to achieve network security. In this phase of the Pilot Plan, we requested data on this issue. During the three months September-November, there were no reported incidences of the procedures being implemented.

## 3. Monitoring Activities

*Cross-Border Transmission Capacity*. The cross-border transmission capacity market is the major focus of our market monitoring. We are interested in detecting conduct or structure that

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6 As explained below, the standardized capacity assessment does not eliminate the possibility of unreasonably restrictive practices in establishing available capacity to the market. Monitoring of the underlying details of the NTC and ATC calculations may be initiated in latter phases of this Pilot Plan.

7 See "Procedures for Cross-Border Transmission Capacity Assessments," ETSO, October 2001; "Definition of Transfer Capacities in Liberalised Market", *Id*. April 2001.

8 By "interconnection" we mean what is commonly understood in the region as the electrical interface between two neighboring control areas.

9 The four interconnections for which ATC was not available was the result of a lack of data on interconnections associated with Bulgaria.

inhibits the development of competition in the region. These concerns include over- or under-reserving capacity, understated cross-border-capacity values, and other circumstances. Our monitoring focuses on the Capacity Assessment, the process used in the region to establish and allocate cross-border capacity values. We compare the allocation of interconnection capacity to the actual usage of that capacity. We have broadened our analysis by considering estimates of physical flows associated with cross-border capacity values produced in the Capacity Assessment. More precisely, we estimate the maximum physical flow that would be associated with the Already Allocated Capacity (AAC) values, as well as the physical limit on the interconnection implied by the NTC values. This allows a more direct assessment of how the real-time physical flows compare to the capacity requirements that are established in the month-ahead capacity allocation process. Such a comparison provides an effective market monitoring screen that can detect potential market issues associated with cross-border trading.

Our analysis estimates the maximum potential physical flow from cross-border capacity reservations (i.e., from AAC). This physical flow arises both from the direct reservation between the two counterparties on the interconnection, as well as potential physical flows from transactions among other TSOs. The analysis reveals the amount of physical capacity that is reserved by the counterparties to the interconnection, versus the physical capacity that potentially would be occupied by loopflow from reservations on other interconnections. We also estimate the physical capacity that is available for cross-border transactions and compare this to the maximum physical flows from all AAC (both the direct AAC from the counterparties and the AAC from all other regional interconnections). Our analysis illustrates that in many instances, the interconnection is over-reserved because the process for establishing capacity rights on the interconnection does not coordinate loopflow effectively. This shortcoming is a standard problem in a contract-path-based transmission reservation process like the one used in the SEE region.

We also estimate the physical limit on each interconnection, which enables us to monitor the physical flow relative to the physical limit. This provides a way of identifying locations where larger NTC values could be particularly beneficial and a way of detecting potential misuse. It also allows us to compare the actual physical flows to the estimated flows from the AAC,

providing a screen that may indicate over- or under-scheduling. Other means of evaluating scheduling issues are limited because we do not currently have access to scheduling data.

*Generation Market Modeling*. With respect to generation markets, REKK continues to develop the network model that was presented in previous reports. During the quarter efforts continued to improve the data used in the model. While not substantial changes have been implemented since the last report, we include the discussion from the previous report for the convenience of the reader.

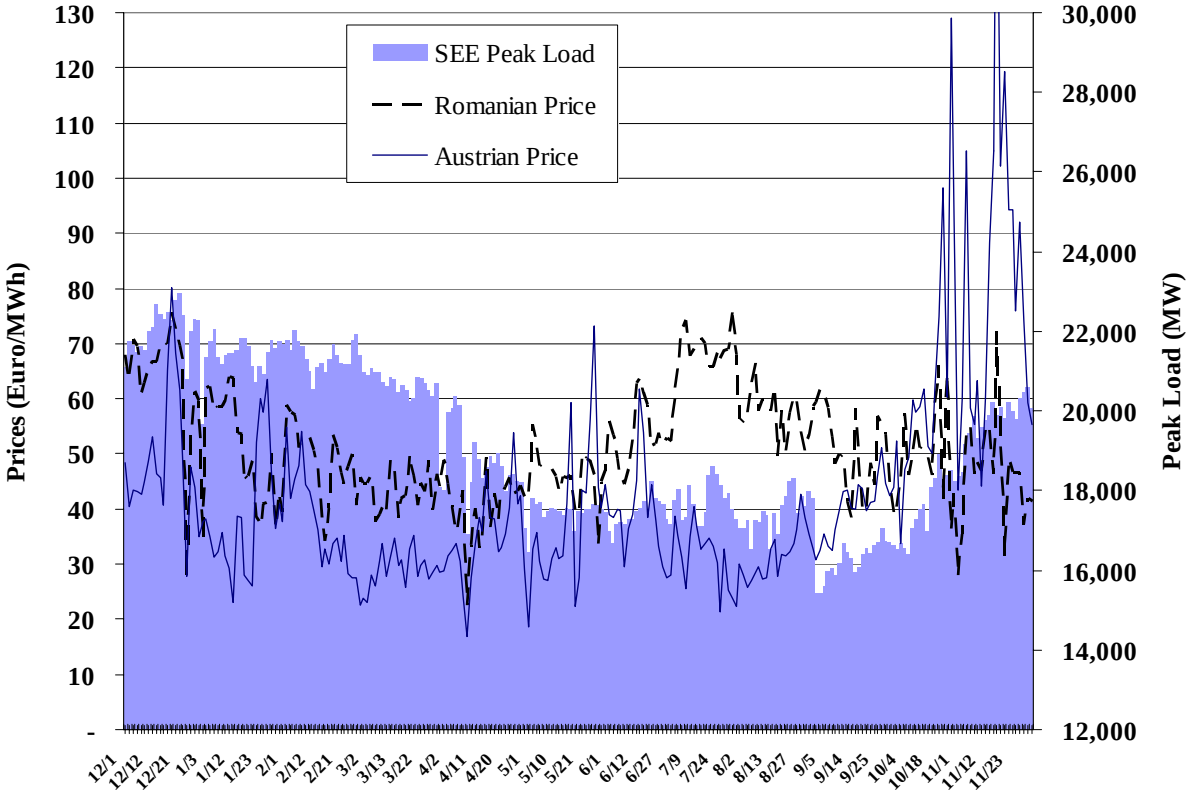
## II. WHOLESALE MARKET ACTIVITY

Summary statistics on overall regional market prices can contribute to effective market monitoring. Understanding price levels and patterns can provide insight into specific time periods and locations that can help focus market monitoring resources. South East Europe is not integrated into a centralized-spot market like other parts of Europe (e.g., NordPool in Northern Europe and National Grid in the U.K). Wholesale market activity in South East Europe is conducted mainly under bilateral contracts among utilities and traders. The exception is in Romania where both a day-ahead spot market and a centralized bilateral contracts market exist. There is also a day-ahead spot market in Austria that, like the Romanian spot market, provides daily prices.[10]

These regional markets can provide a good indicator of regional market conditions. Accordingly, Figure 1 provides the Romania and Austrian prices, as well as daily peak load in the SEE region. This provides two indicators of market performance. First, there is the price comparison between Romania and Austria. Second, there is the correlation of price levels to load levels.

[10] The Romanian bilateral contracts prices are published on a monthly basis.

**Figure 1: Regional Spot Market Prices and SEE Load**
**September – November 2007**

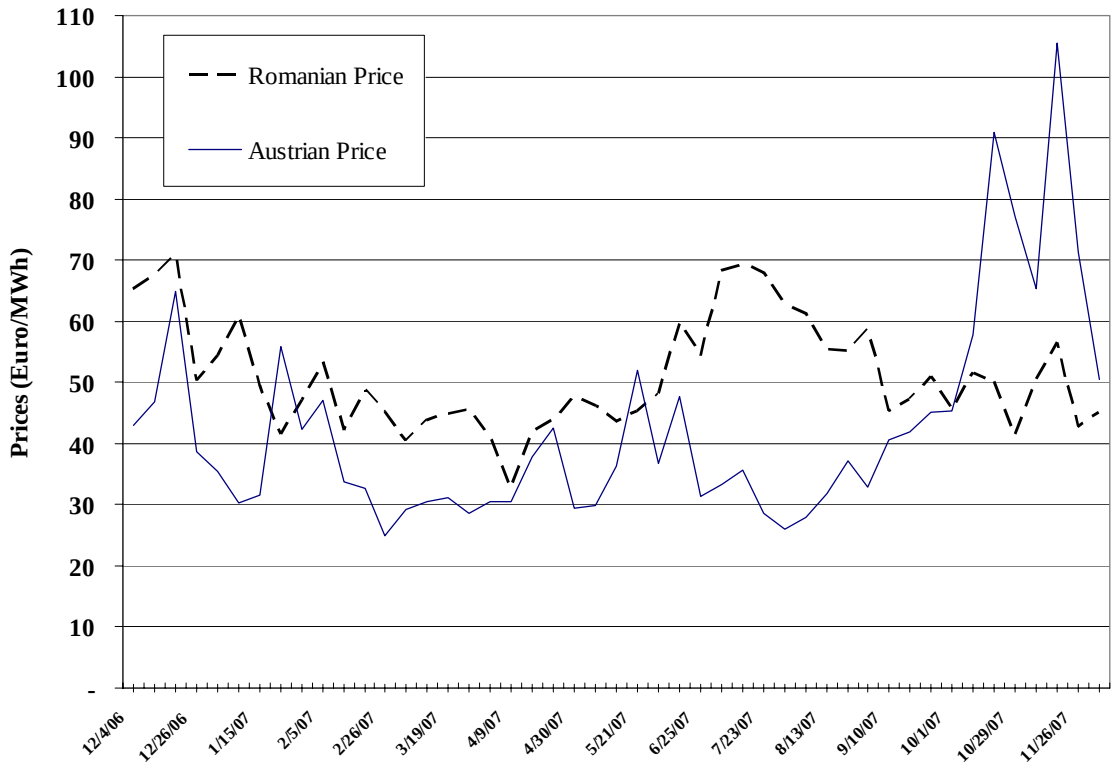



*Note:* Excludes Bulgarian load data.

*Regional Price Comparison*. During the summer, prices were higher in Romania than in Austria but the situation changed in the fall, when volatility and high prices were experienced in Austria. As indicated in previous reports, the prices between Romania and Austria diverge significantly in many instances. This may indicate the absence of effective price arbitrage between the regions, which is either caused by the lack of transmission capacity or by poor market integration. At this point in time, we have not sought to determine the underlying causes of the divergence.

In order to smooth the volatility in the series, we calculated average weekly prices and these are presented in Figure 2. With the removal of daily volatility, the series shows more clearly periods when prices were divergent between the two locations.

**Figure 2: Comparison of Romanian and Austrian Prices -- Weekly Average**




In previous reports, we hypothesized that one explanation for price divergence may be related to access to west-to-east transmission capacity through the transmission systems in the western part of the SEE region. However, the hypothesis would have to be expanded to include congestion in the opposite direction as well because the prices are higher in Austria in recent months. We have also received indications from market participants that perhaps the Romanian data does not reflect the true market conditions in the SEE or even in Romania. We will investigate whether better price data is available and will continue to monitor prices in order to illuminate the situation.

## III. NETWORK CONGESTION

Network congestion can arise in the *planning horizon* as well as in the *operating horizon*. We use the term planning horizon to mean the time between when the monthly capacity allocation is made and the day-ahead time frame. We use the term operating horizon to be the time between

the day ahead and the real-time.[11] In the planning horizon, congestion arises when posted transmission capacity (ATC) is zero. In the operating horizon, congestion arises due to unit commitment or dispatch that is not feasible within the transmission operating parameters. We analyze congestion in both the planning horizon, as well as the operating horizon. In the planning horizon, we use ATC as the indicator of congestion. In the operating horizon, we use curtailments of transactions pursuant to UCTE guidelines as indicators of congestion.

## A. Planning Horizon Congestion

As noted above, NTC and ATC calculations are established in the Capacity Assessment pursuant to UCTE guidelines. We use monthly ATC values as indicators of constraints in the region. If ATC is zero at a particular interconnection, the network is constrained because no incremental market activity can occur that relies on the particular interconnection. There are 24 interconnections that link the participants in the Pilot Plan. Of these interconnections, we were able to obtain ATC data on 20 of them (lack of participation from Bulgaria prevented compiling data on the four other interconnections). A summary of these interconnections and monthly ATC values is shown in Table 1.

[11] We use these terms for our discussion only and are not meant to correspond to any term of art that may be currently in use.

**Table 1: Summary of Monthly ATC Values**

| Interconnection | ATC Sep 07 | ATC Oct 07 | ATC Nov 07 |
|---|---|---|---|
| Albania to Montenegro | 200 | 300 | 200 |
| Albania to Serbia | 210 | 315 | 210 |
| Bulgaria to Romania | Unavailable | | |
| Bulgaria to Serbia | Unavailable | | |
| Bosnia & Herzegovina to Croatia | 410 | 387 | 440 |
| Bosnia & Herzegovina to Montenegro | 323 | 210 | 180 |
| Bosnia & Herzegovina to Serbia | 4 | 40 | 17 |
| Croatia to Bosnia & Herzegovina | 300 | 25 | 100 |
| Croatia to Serbia | 75 | 55 | 151 |
| Macedonia to Serbia | 0 | 90 | 130 |
| Montenegro to Albania | 100 | 100 | 100 |
| Montenegro to Bosnia & Herzegovina | 340 | 319 | 400 |
| Montenegro to Serbia | 150 | 470 | 230 |
| Romania to Bulgaria | Unavailable | | |
| Romania to Serbia | 0 | 0 | 0 |
| Serbia to Albania | 0 | 0 | 0 |
| Serbia to Bulgaria | Unavailable | | |
| Serbia to Bosnia & Herzegovina | 55 | 5 | 83 |
| Serbia to Croatia | 70 | 40 | 130 |
| Serbia to Macedonia | 0 | 0 | 0 |
| Serbia to Montenegro | 95 | 255 | 170 |
| Serbia to Romania | 0 | 50 | 35 |

*Note: ATC Values reflect the result of monthly allocations. ATC for interconnections with Bulgaria were unavailable due to lack of data from this participant.*

These monthly values are adjusted for allocations from monthly auctions that have been initiated on many of the interconnections starting in 2007. Therefore, the ATC reported herein is that which would be available at the beginning of the month for additional monthly purchases or for weekly and daily purchases.

As the table indicates, ATC was zero in one or more of the months studied on five paths. Otherwise, capacity was generally available. However, large regional trades would be limited because on many paths (nine out of eighteen) capacity was below 50 MW in one or more of the months. We have not obtained data at this stage of the monitoring plan that would enable us to indicate whether such transfers were abandoned as a result of insufficient ATC.

Finally, the standardized Capacity Assessment does not eliminate the possibility of unreasonably restrictive practices in making capacity available to the market. This issue is discussed in more detail below. Part of our monitoring effort seeks to detect such issues. We seek to initiate further monitoring of the underlying details of the NTC and ATC a latter phase of the Pilot Plan.

## B. Operating Horizon Congestion

In addition to congestion arising in the planning horizon when ATC is zero, we also collected data associated with congestion management measures.

UCTE[12] Policy 4 of the UCTE Operations Handbook is titled "Coordinated Operational Planning". This policy establishes practices to coordinate, among other things, the capacity assessment and day-ahead and real-time congestion management. These guidelines include the potential to withdraw interconnection capacity and curtail transactions.

We requested that the TSOs identify any instances when this may have occurred, starting with April 2007. While we have not received responses for all entities in all months, there have been no curtailments reported for the period September to November. Since we began collecting this data in April, only one instance of curtailments has been reported. The reported curtailment occurred for four days in April. We have learned that TSOs may take measures to avoid day-ahead or real-time congestion by coordinating with the generating companies scheduling changes. We continue to be interested in these processes and will continue to monitor and gather new information as to these operating procedures.

## C. Regional Peak Flows

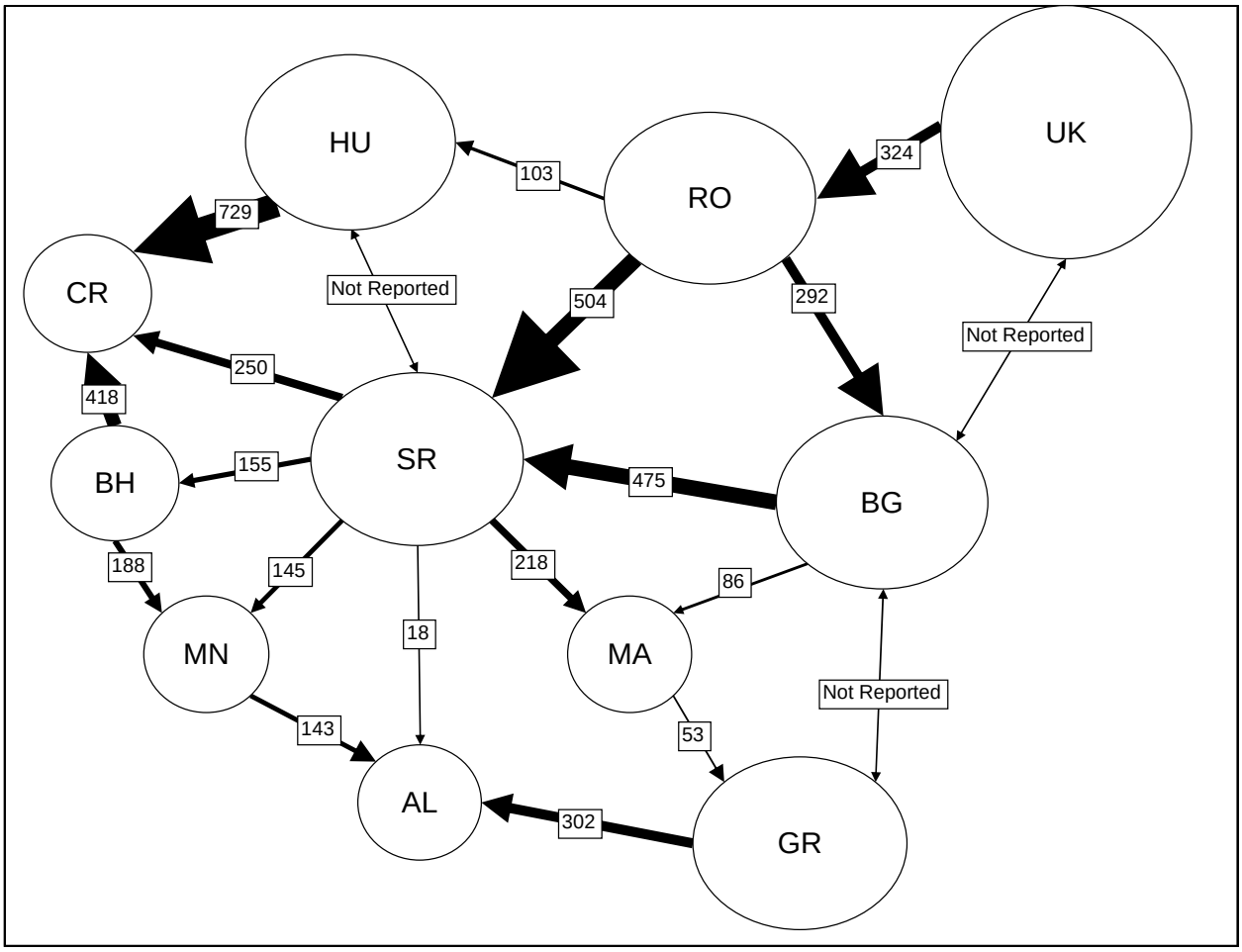
As a final indicator of regional market conditions and transmission system utilization, we illustrate the peak physical exchanges among TSOs for each of the months September, October, and November. We calculated the peak interconnection flow between each country on the day of the month when regional peak load was the highest. Figure 3 shows the interregional flows for November. We show November because both regional load and flows between TSOs was

[12] UCTE is the acronym for "Union for Coordinated Transmission of Electricity".

highest in November. Comparable figures for September and October are presented in Appendix B.

Where the data is available, the arrows in Figure 3 indicate the direction of flows as well as their relative magnitude. While the magnitude of flows at the peak hour varies across the interconnections, the general flow is from Ukraine to the south and west into Bulgaria, Romania, and Serbia.[13] The pattern is consistent with what most observers of the region would expect.

**Figure 3: Regional Flows at November Peak Load**




*Note*: Bulgaria to Serbia peak flow is estimated based on monthly volume, see footnote in text.

[13] The Bulgaria-to-Serbia interconnection was estimated using monthly exchange volumes, which were available on the UCTE website. We assumed the ratio of peak flow to total volume on the Bulgaria-to-Serbia interconnection was the same as the ratio on Romania-to-Serbia interconnection. We had the data on the Romania-to-Serbia interconnection to calculate the ratio and so we applied the ratio to the Bulgaria-to-Serbia monthly volumes to get the estimated peak flow.

## IV. MARKET MONITORING ANALYSES

In the previous sections, we examined overall market conditions and identified network congestion. Such analysis is designed to focus monitoring activities on times and locations when market power is most likely to occur. In this section of the report, we provide market monitoring analyses that calculate the utilization of interconnections and seek to detect competitive concerns. We evaluate the usage of the interconnected network in South East Europe with the objective of identifying potential areas for improvement that can advance the development of the market.

We have identified two other critical market monitoring issues beyond the monitoring of the interconnections. In particular, we seek monitoring of sales and purchases and analysis of generation markets. With respect to sales and purchases, we seek to detect correlation between prices and congestion to determine whether further investigation regarding anticompetitive conduct is warranted. So far, we have been unsuccessful in collecting the required data to accomplish this monitoring. We anticipate further efforts to gather this data at later phases of the project. With regard to generation markets, substantial progress has been made on the generation modeling and this is discussed in Section I.

### A. Capacity Assessment

Power is traded among participants in South East Europe using cross-border transmission capacity. Therefore, the availability of cross-border capacity is critical to a vibrant regional market. Access to transmission capacity on interconnections that link TSOs in the region is allocated in accordance with procedures set forth by UCTE and endorsed by the European Transmission System Operators (ETSO). The procedures currently employed to allocate this capacity, known as the Capacity Assessment, is based on an estimate of the maximum potential power transfers between two TSOs. This estimates is derived from a “base case” power flow model that reflects anticipated load and generation conditions for the timeframe of interest, e.g., the month ahead. The input data includes the thermal ratings of transmission facilities, the forecast load, and the output range and costs of generators.

The underlying basis of the Capacity Assessment is the estimate of Total Transmission Capacity (TTC). TTC is the maximum possible flows that can be safely accommodated over the interconnection given these base case assumptions about load, generators, transmission conditions, and scheduled transfers among TSOs (called *base case exchanges* or "BCEs"). Essentially, the TTC is estimated by modeling an increasing transfer of power between two TSOs and detecting the maximum transfer amount at the point where transmission constraints are reached. Net Transmission Capacity (NTC) is defined as TTC less Transmission Reliability Margin (TRM). TRM is a margin of capacity that is reserved by TSOs in order to respond to operational uncertainties. It typically accounts for about 10 percent of the TTC, but can vary somewhat.

NTC is then divided between capacity that which is allocated through yearly and monthly auctions (Already-Allocated Capacity (AAC)), and Available Transmission Capacity (ATC). Hence:

TTC = maximal safe power transaction between two TSOs;

NTC = TTC -TRM;

NTC = AAC + ATC;

The Capacity Assessment estimates the maximum transfer between two TSOs without regard to the maximum transfers betweens any other TSOs. In other words, it is a *non-simultaneous* estimate of the maximum transfer capacity and does not account for the fact that the interconnection's physical capacity can be used up by transactions between neighboring TSOs (a phenomenon known as loop flow). This is the standard short-coming of *contract-path*-based estimates like those in the Capacity Assessment: the estimated transfer capability is estimated in isolation of transactions between other TSOs.[14] In reality, the estimated capacity on an interconnection could be substantially used up in real time by transactions on other systems and

[14] This is mitigated somewhat by using base case exchanges in the TTC calculations, which are meant to reflect potential regional transactions.

the actual physical capacity could be insufficient to accommodate all transfers. When this happens, real-time congestion management is necessary.

The alternative to a contract-path-based system is a flow-based system where the transfer capability on an interconnection reflects the other uses on the system. In a flow-based system, all regional transactions are taken into account to determine the regional capacity that is available for a particular transaction.[15] We highlight some of the differences between the contract-path-based allocations and flow-based allocations in our analysis below.

## B. Physical Flows, NTC, and AAC

Our monitoring of the cross-border transmission capacity focuses on comparing the transmission capacity that is made available to the physical usage of the system. Our analysis seeks to illuminate the process of reserving and scheduling on the interconnection with the goal of identifying potential impediments to competition. Using values from the Capacity Assessment and data on actual physical flows, we seek to develop meaningful comparisons between reserved uses of the system (AAC) and actual physical flow. To do this, we calculate certain measures of capacity from a flow-based perspective. More precisely, we identify potential physical flows associated with the various contract-path-based estimates in the Capacity Assessment (viz., NTC and AAC) using Power Transfer Distribution Factors (PTDFs).

PTDFs indicate what portion of a transaction between two TSOs will physically flow over various interconnections. Typically, most of the physical flow associated with a transaction between two TSOs will flow on the interconnection between them. However, a significant portion can flow over other interconnections. For example, only 64 percent of a transaction from Serbia to Montenegro will flow on the Serbia to Montenegro interconnection. Seventeen percent of it will flow on the Serbia to Croatia Interconnection and ten percent will actually flow easterly to Romania.

Therefore, with respect to AAC, if all AAC on an interconnection is actually scheduled in real time, only a portion of it actually flows on the physical facilities. For example, if the PTDF on

[15] The coordinated auction office that is under consideration in the SEE region is a flow-based system.

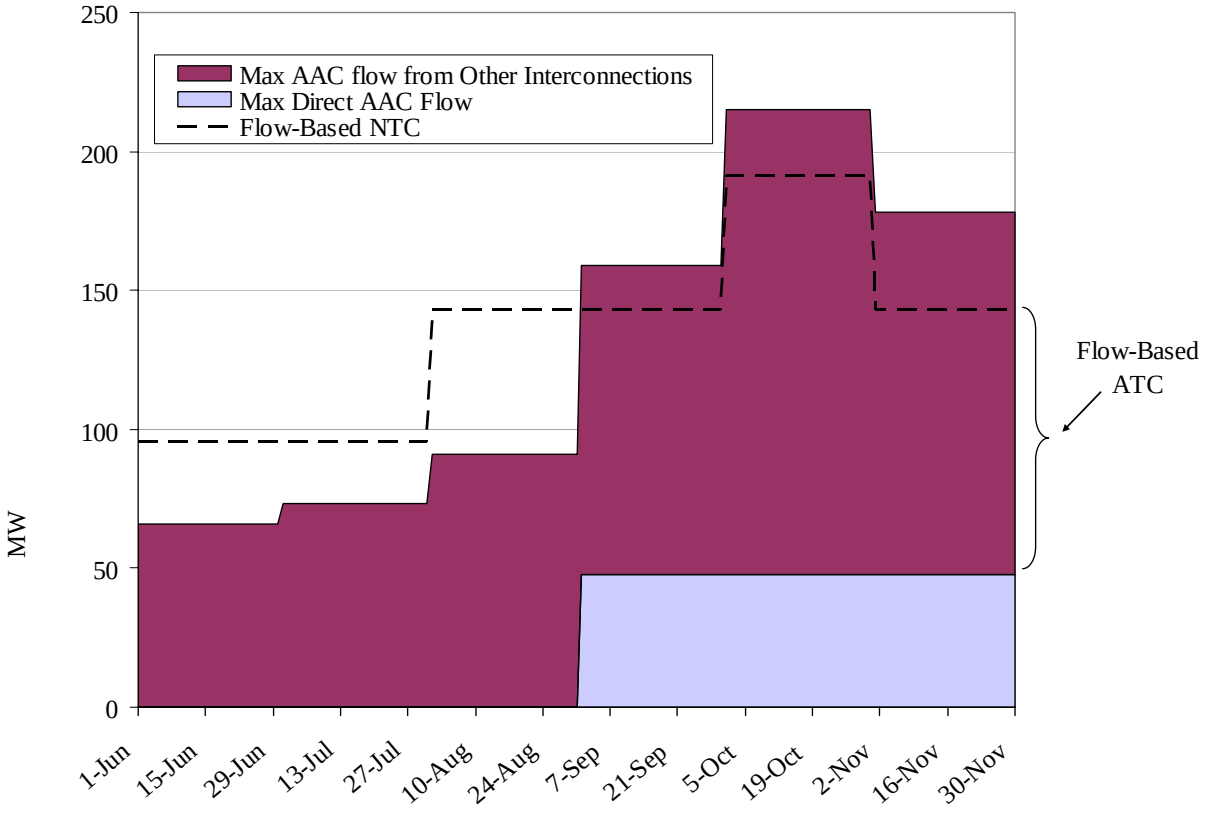
an interconnection is 60 percent and the AAC is 100 MW, then a maximum of 60 MW would actually flow on the interconnection from those reservations. However, the interconnection would experience physical flow from AAC over other interconnections, i.e., loopflow. Accordingly, we use the AAC values on each interconnection to estimate the maximum flow from AAC by other TSOs. We refer to these measures as flow-based AAC values because they indicate the physical flows that would arise from the AAC if scheduled in every hour.[16]

We also estimate the amount of physical capacity that is available on the interconnection as determined by the Capacity Assessment. Recall that the NTC value produced by the Capacity Assessment is an estimate of the largest transaction that can be accommodated between two TSOs above the base case dispatch and base case exchanges (adjusted for TRM). Not all of the incremental transaction will physically flow on the interconnection between two such TSOs. The amount that would flow on the interconnection, corresponds to the physical flow-based capacity available on the interconnection, is the NTC times the PTDF between the two TSOs. Hence, if the PTDF is 60 percent and the NTC is 50 MW, 30 MW of physical capacity is available on interconnection. We refer to this as the "flow-based NTC". A comparison of this flow-based NTC to the flow-based AAC discussed above provides important insight into the capacity allocation process in the region.

In order to clarify the nature of these metrics, an example from the analysis is helpful. Consider the Albania-to-Montenegro interconnection. We choose this interconnection only because it is first in alphabetical order.

[16] As explained below, we refer to these as "maximum" because we do not consider the physical flow from other interconnections that flow in the opposite direction (i.e., counterflow).

**Figure 4: Flow-Based AAC and NTC Values**
**Albania-to-Montenegro Interconnection**




The red-colored area is the Maximum flow associated with AAC from other interconnections (i.e., loopflow). It represents what would flow on the Albania-to-Montenegro interconnection if all TSOs with AAC on other interconnections that have positive PTDFs with respect to the Albania-to-Montenegro interconnections fully-scheduled their AAC. Using only TSOs with positive PTDFs in relation to the interconnection implies that no counter-flow is considered -- only physical transactions associated with AAC on interconnections that would flow in the Albania-to-Montenegro direction are included. This is why the term “maximum” is used. In most instances, of course, transactions that contribute to physical power flow in both directions will be in effect at any given time.

The lightly-colored blue area is the figure is the maximum direct flow associated with AAC on the Albania-to-Montenegro interconnection. It represents what would physically flow if all the reservations from Albania to Montenegro were scheduled. It is the “maximum” because we assume the AAC is fully scheduled. The sum of the blue area and the red area provides the

maximum potential flow over the interconnection. Hence, the top of the red-colored area represents the total maximum AAC flow.

The dashed line on the figure is the flow-based NTC. As described above, this is the maximum amount of physical capability that would be available to accommodate AAC. When the sum of the red areas and the blue areas exceeds the NTC flow, the interconnection is over-allocated. This would have been the case in September, October, and November. This is not unexpected because there is very little direct coordination of the AAC on different interconnections. In the event the actual flows associated with maximum AAC was realized, real-time congestion management measures would be necessary to maintain reliability of the system. This is not likely to be frequently needed because not all reservations are ultimately scheduled, and some schedules will provide counterflow and relieve the physical loading on the interconnection. This is the value of real-time congestion management – it allows the operators to respond to unforeseen circumstances, such as the event when schedules are heavily weighted toward reservations that contribute to flow in one direction.

In order to avoid encumbering the figure with additional data series (and potentially obscuring the results), ATC is not shown explicitly. However, as Figure 4 shows, the flow-based ATC is the difference between the Flow-Based NTC and the Max Direct AAC Flow.[17] Therefore, because ATC=NTC-AAC, when Flow-Based NTC equals Max Direct AAC Flow, then ATC is zero. When Flow-Based ATC is greater than Max Direct AAC, then ATC is non-zero. On this particular interconnection, ATC is greater zero in each month.

The figure also reveals that outside transactions (red shaded area) have the potential to contribute to power flows in greater proportion than the direct transactions between TSOs (light-blue shaded area). Given the current system of allocating and compensating for transmission capacity, other TSOs' are using this interconnection for transactions yet not paying for it. Additionally, because ATC values generally ignore flows caused by AAC on other interconnections, the parties to an interconnection may post substantial ATC when the flow-

[17] Actual contract-path ATC (the value that is posted on the interconnection) is the flow-based ATC divided by the PTDF between the two parties to the interconnection. Because this PTDF is less than one, this conversion results in an ATC value greater that the Flow-Based ATC.

based capability off the interconnection is already fully allocated. This is a standard shortcoming of the contract-path-based allocation methodologies and is reminiscent of justifications for flow-based methods.

On each interconnection, we also compare actual physical flow to the implicit physical limit on the interconnection. The physical flows are provided by participating TSOs. The implicit physical limit is derived from the flow-based NTC and base case assumptions regarding "base loopflow" and exchanges. Recall that the flow-based NTC, which is shown in Figure 4 for the Albania-to-Montenegro interconnection, is the amount of additional physical flow that can be accommodated on the interconnection above the base case model. Therefore, the flow-based NTC plus any physical flows on the interconnection from the base case model represents the physical limit on the interconnection.

Physical flows on the interconnection in the base case rise from two sources: "base loop flow" and base case exchanges (BCEs). Base loop flows, called *natural flows*, are the flows on the interconnection in the base case prior to any exchanges between TSOs. It is the flow from the base dispatch. These values are provided by the TSOs on a monthly basis. In addition to the natural flows, we also account for flows on the interconnections resulting from the BCEs. BCEs are part of the base case model and, therefore, occupy physical capacity in the model. We received BCE data from the TSOs and, because they are reported as transactions between TSOs, we use the PTDFs to convert them to physical flows.

The sum of the flows from the natural flows and the physical flows from the BCE represent the base physical flows.[18] The flow-based NTC (referred to as NTC Flow in the figures) indicates the maximum amount of physical capacity available for incremental transfers beyond the base case. Therefore, the sum of NTC flow, the natural flows, and the PTDF-allocated BCEs, represents the implicit physical limit on interconnection. We call it an implicit limit because we have derived it from these underlying values; as opposed to receiving such data directly form the base case models. However, we are in the process of requesting this data.

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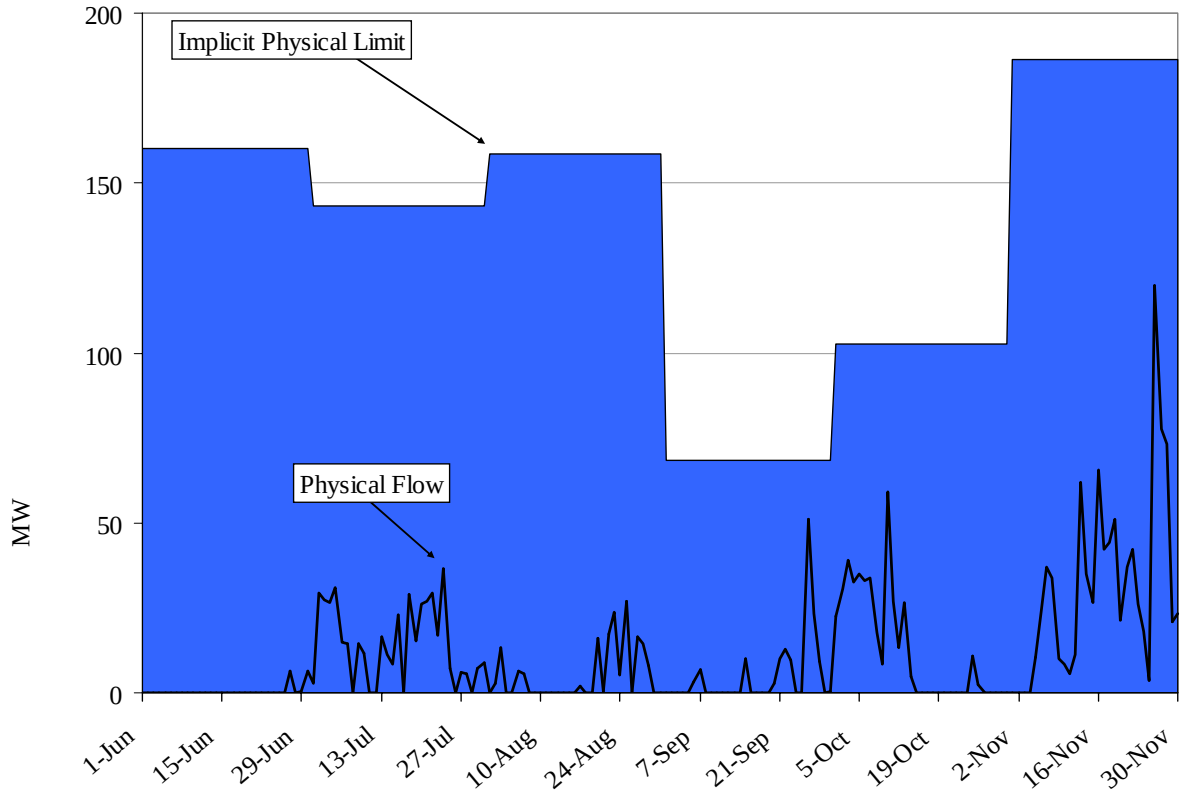
[18] We treat negative values for natural flows as zero. Likewise, BCEs that have a negative physical flow (counterflow) on the interconnection are not included. Including negative values we would improperly under estimate the physical capacity.

Figure 5 shows an example of our analyses on the Albania-to-Serbia Interconnection. We use this as an example because it is the first interconnection in alphabetical order that had non-trivial flows on the interconnection.

**Figure 5: Physical Flow and Implicit Physical Operating Limit**
**Albania-to-Serbia Interconnection**




The figure is relatively straightforward. It shows the daily physical flows on the interconnection compared to the implicit physical operating limit. For this particular interface, the physical flows are within the operating limit. In the summer, the flows were somewhat below the limit. This could be explained by the unreserved capacity (i.e., positive ATC) that remained on the interconnection, as shown in Figure 4. If it had been the case that ATC was zero during time periods when flow was significantly below the physical limit, the data would suggest that additional transmission capacity could be made available in the Capacity Assessment.

The Implied physical limit on the Albania-to-Serbia interconnection, like other interconnections we evaluate below, fluctuates substantially, which may indicate potentially modeling concerns if

it cannot be explained by changes in system topology. We seek physical operating data on each interconnection that will permit further evaluation.

In the following subsection, we use the analysis developed in Figure 4 and Figure 5 for each interconnection. This provides a basis for our discussion of key observations and conclusions on a case-by-case basis.

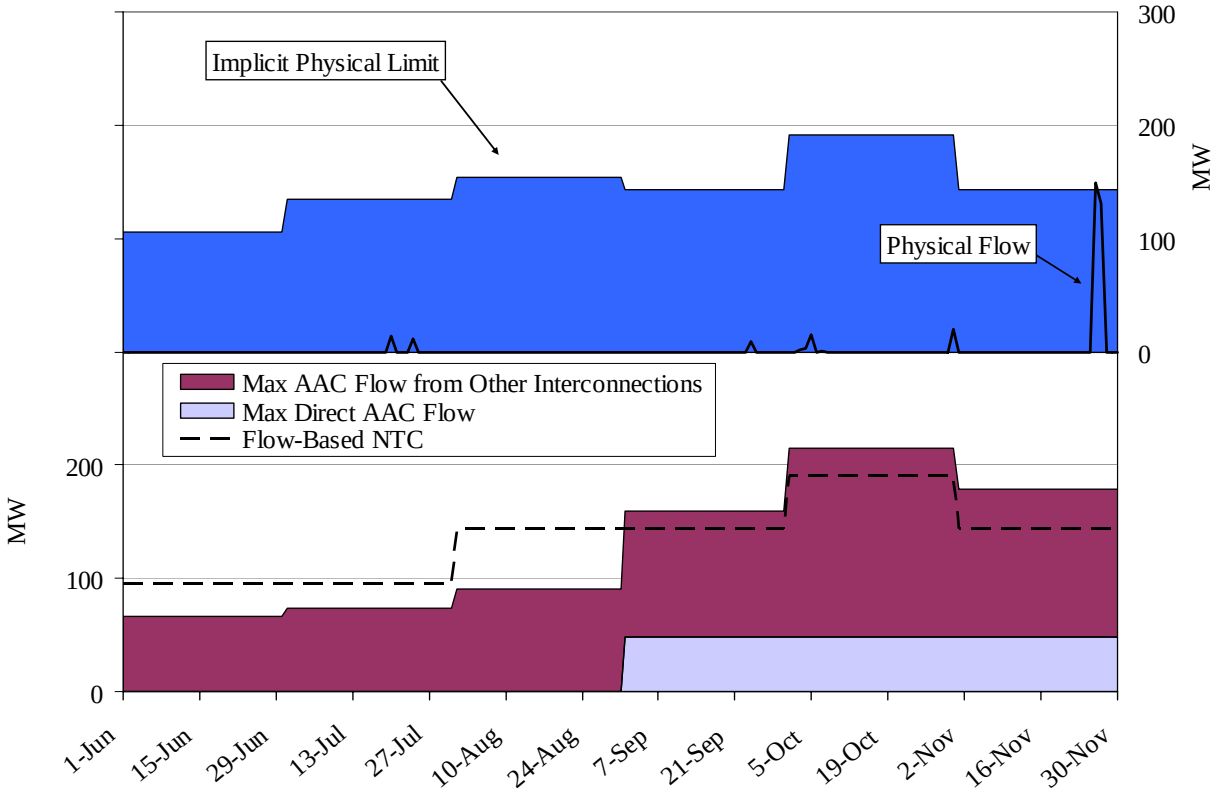
## C. Analysis of Individual Interconnections

In this subsection, we conduct individual analysis of each interconnection using the methods described in the previous subsection. As discussed above, there are 22 interconnections that link the Pilot Plan participants. Not all participants provided the necessary data to conduct our analysis. However, if at least one party to the interconnection provided data, then it was possible to perform the analysis. In the case of the interconnections involving Bulgaria, we estimated key variables because of Bulgaria's lack of response to the program. We are still hopeful that cooperation from Bulgaria will be forthcoming. The only interconnections that were not possible to evaluate were the two interconnections between Serbia and Bulgaria. Neither Serbia nor Bulgaria provided the physical flow data necessary to conduct the analysis.

We seek to identify three primary outcomes that have potential competitive or efficiency implications. The first outcome is one in which ATC is zero or close to zero while physical capacity remains unused. In such a situation, the unused capacity could be made available through ATC. The second outcome is one in which physical flows exceed both the physical limit and the maximum flow expected from AAC. Such a scenario would be consistent with unscheduled use of the system by parties within the region or excessive loop flow from outside the region. The third outcome is one in which the ATC is zero and the physical flows are close to or exceed the physical limit. On these interconnections, the transmission constraint is binding and, therefore, additional interconnection capacity would benefit the market. Accordingly, we recommend careful review of the Capacity Assessment in order to determine whether higher TTC values are possible.

The analyses of individual interconnections are presented in alphabetical order, beginning with the Albania to Montenegro Interconnection shown in Figure 6.

**Figure 6: Analysis of the Albania-to-Montenegro Interconnection**




The lower panel in the figure was used as the example in Figure 4. We described how the interconnection has the potential to become over allocated due to the lack of coordination related to AAC on other interconnections. However, the upper panel in the figure shows that there was little physical flow on this interconnection. The non-zero ATC on this interconnection is consistent with the physical flows being substantially below the physical limit. The analysis does not indicate to us circumstances that give rise to efficiency issues or competitive concerns.

**Figure 7: Analysis of the Albania-to-Serbia Interconnection**

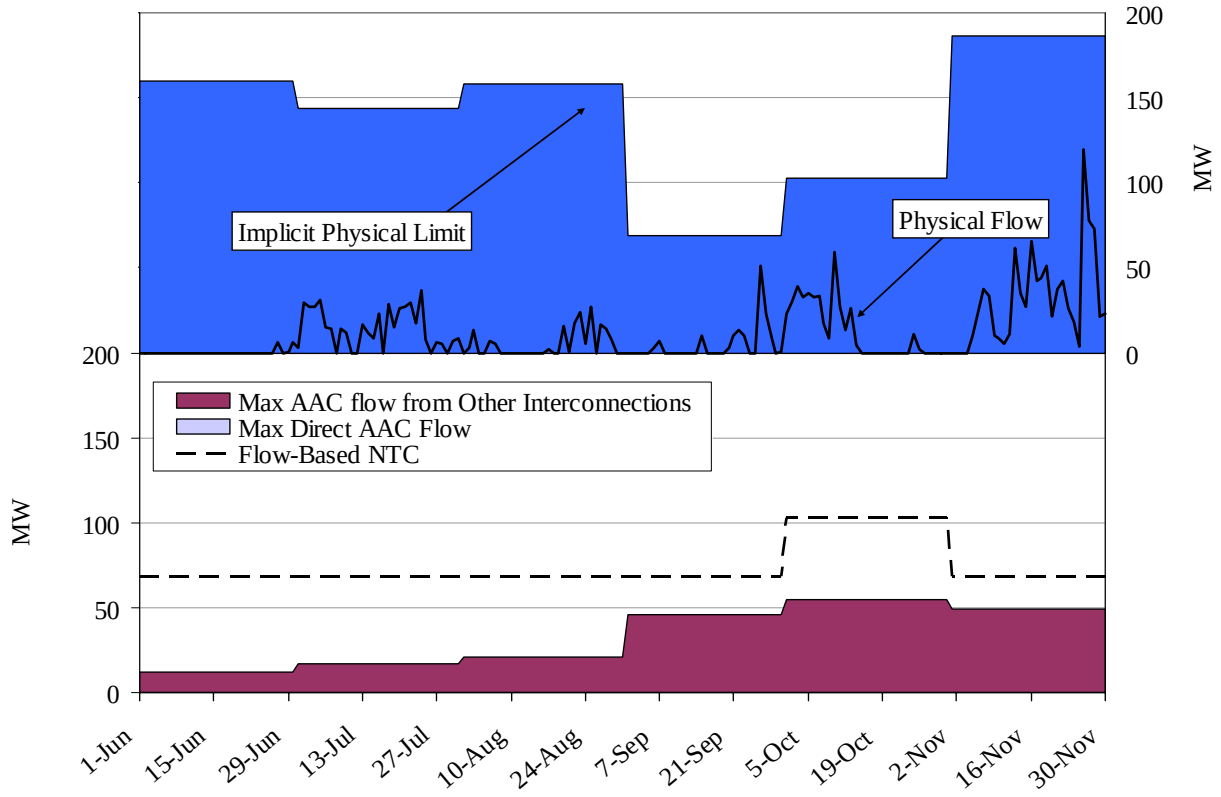



Figure 7 shows the Albania-to-Serbia interconnection. There is no direct flow from AAC on this interconnection (i.e., no reservations were made) and there is ample flow-based ATC (the difference between Flow-Based NTC and Max Direct AAC Flow, see Figure 4). We also see that physical flows are well within the physical limit, likely explained by positive amounts of ATC throughout the period. In general, this interconnection is not reserved and does not experience significant physical flow. The analysis does not indicate to us circumstances that give rise to significant efficiency or market issues.

**Figure 8: Analysis of the Bulgaria-to-Romania Interconnection**

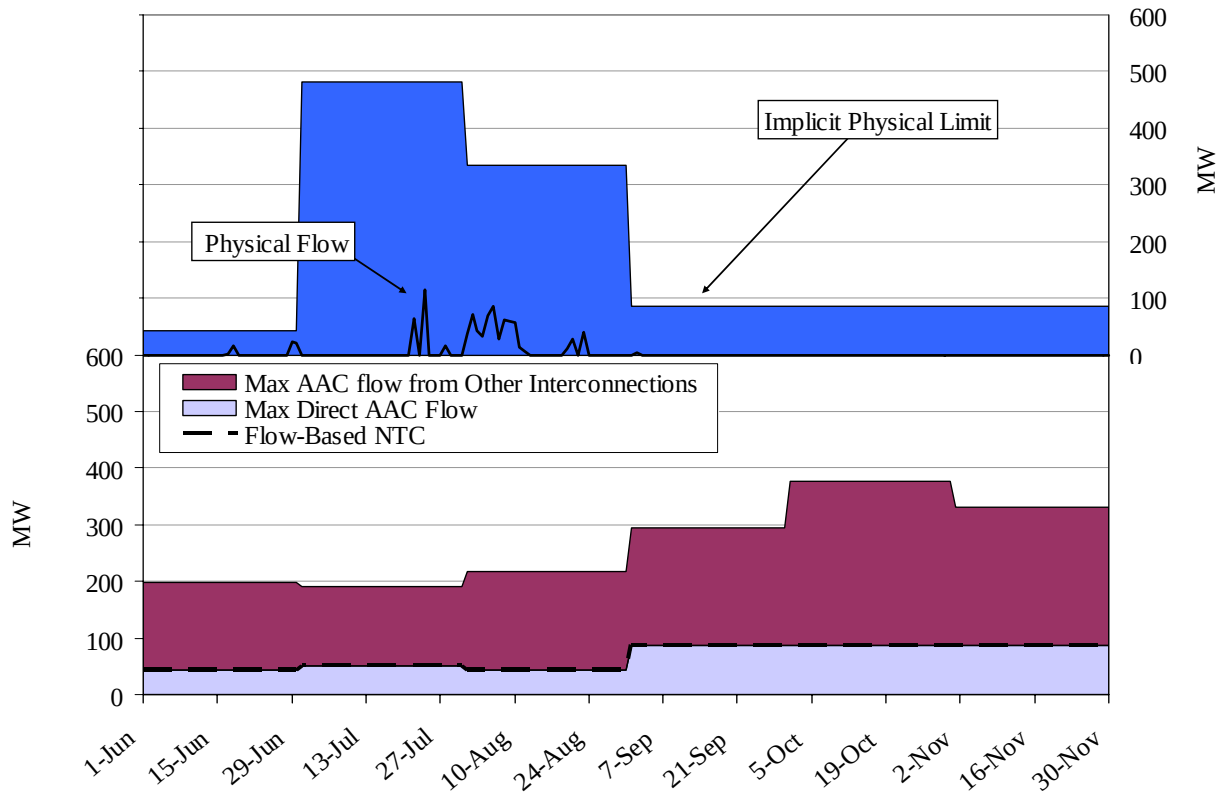



Figure 8 shows the Bulgaria to Romania Interface. NTC Flow in this figure is exactly equal to the Max Direct AAC Flow (the NTC Flow line exactly follows the top of the light-blue area). This means ATC was zero throughout the time period. However, during July and August, there was significant physical capacity available. This could be the result of capacity being reserved, but not utilized. However, our data currently does not permit a further evaluation of this question.[19] Our concerns are eased somewhat by the fact that the predominant flow on this interconnection is in the opposite direction (see Figure 3).

[19] We also note that it was necessary to make an assumption about AAC because the Bulgarian data was not available. In particular, because Bulgaria does not readily post its ATC and NTC values, we estimated these values based on the pattern of reservations on the Romanian side of the interconnection. Recall that ATC on an interconnection is allocated one-half by each TSO. We assumed that because all of the ATC that was allocated to Romania was reserved, we assume that the same was true for Bulgaria. This is a reasonable assumption given that the value of the interconnection should be the same regardless who actually auctions the capacity.

Finally, the lower part of the chart indicates that significant loopflow from other TSOs is a potential on this interconnection, although the physical flow data does not indicate this to be the case in fact.

**Figure 9: Analysis of the Bulgaria-to-Serbia Interconnection**

<<Analysis was not possible due to lack of key data from *Bulgaria* and *Serbia* >>

**Figure 10: Analysis of the Bosnia & Herzegovina-to-Croatia Interconnection**

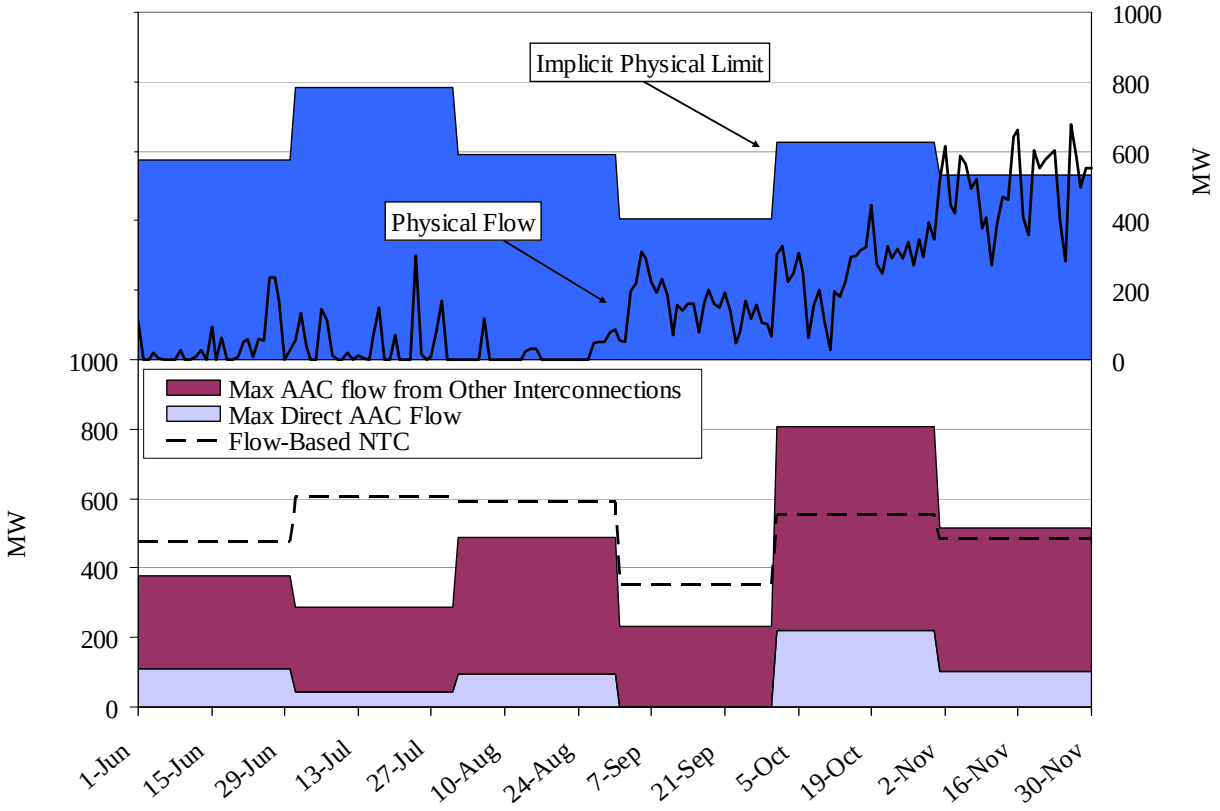
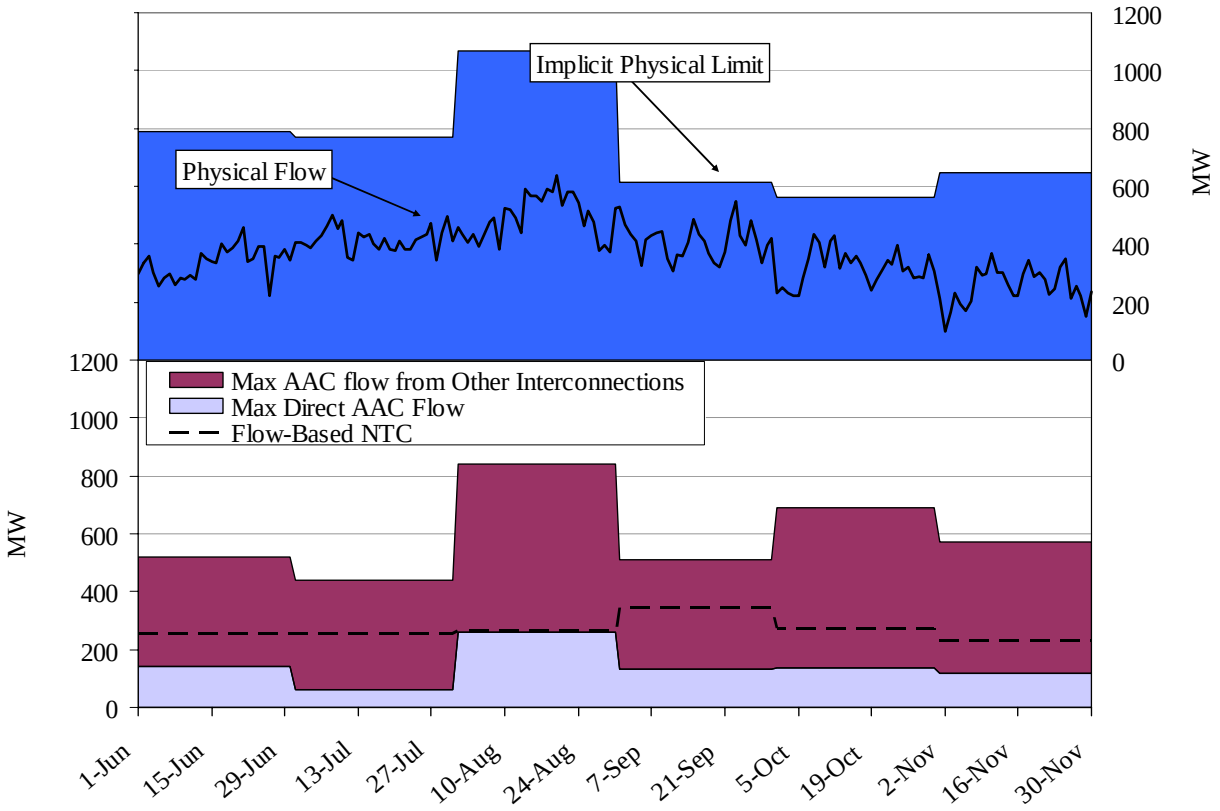



Figure 10 shows the analysis of the Bosnia and Herzegovina to Croatia interconnection. There is generally ATC on this interconnection. This is evident from the lower panel of the figure which shows NTC Flow is greater than Max Direct AAC flow on a sustained basis during the period. We also note that loopflow from other interconnections could be substantial. Indeed, in many instances during the period, physical flows (shown in the top panel) were significantly greater than Max Direct AAC (lower panel). This is consistent with transactions between other TSOs creating loopflow on this interconnection. There was a notable increase in physical flow in the latter part of the period (in some instance exceeding the physical limit). In addition, the physical flows during that latter period exceeded the maximum AAC flow (the light-blue and red areas

combined), something that is consistent with participants engaging in unscheduled transactions. We will monitor this situation to determine whether is develops into a sustained pattern. Aside from this point, the analysis does not indicate to us circumstances that give rise to efficiency or market concerns.

Figure 11 shows the analysis of the Bosnia & Herzegovina to Montenegro interconnection.

**Figure 11: Analysis of the Bosnia & Herzegovina-to-Montenegro Interconnection**




On this interconnection, lower panel again reveals the potential for significant loopflow form other interconnections. The physical flow data, which reaches up to 600 MW, is consistent with this phenomenon. Therefore, substantial physical usage of the facilities is occurring but not from direct AAC between the parties.

During most of the time period, ATC was relatively small (and even zero in August). This occurred during periods when substantial physical capacity was available. This is a case where a closer evaluation of the NTC value could create additional ATC, especially given the significant flows that the interconnection experiences.

**Figure 12: Analysis of the Bosnia & Herzegovina-to-Serbia Interconnection**

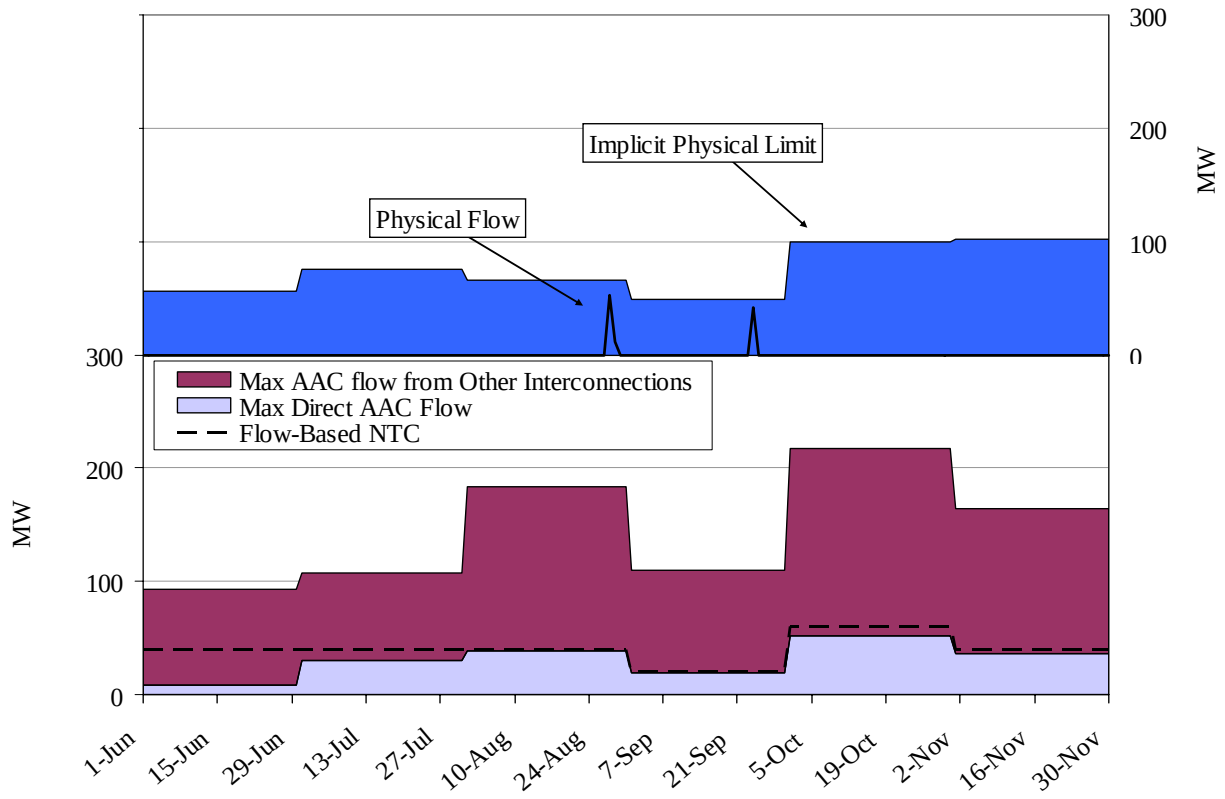



Figure 12 shows the analysis of the Bosnia & Herzegovina to Serbia interconnection. This interconnection is relatively inactive. Only a small amount of capacity is reserved and physical flow is minimal. We do observe the potential for large physical impact from other TSOs. But this is not evident in the physical flow data.

Figure 13 below shows the analysis of the Croatia to Bosnia and Herzegovina interconnection. On this interconnection, ATC is generally positive, with the exception of October. Like many of the other interconnections, the potential for physical flows from others' AAC is substantial. However, the physical flows during the period studied was consistent with the direct AAC on the interconnection. The analysis does not indicate to us circumstances that give rise to efficiency or market concerns.

**Figure 13: Analysis of the Croatia-to-Bosnia & Herzegovina Interconnection**

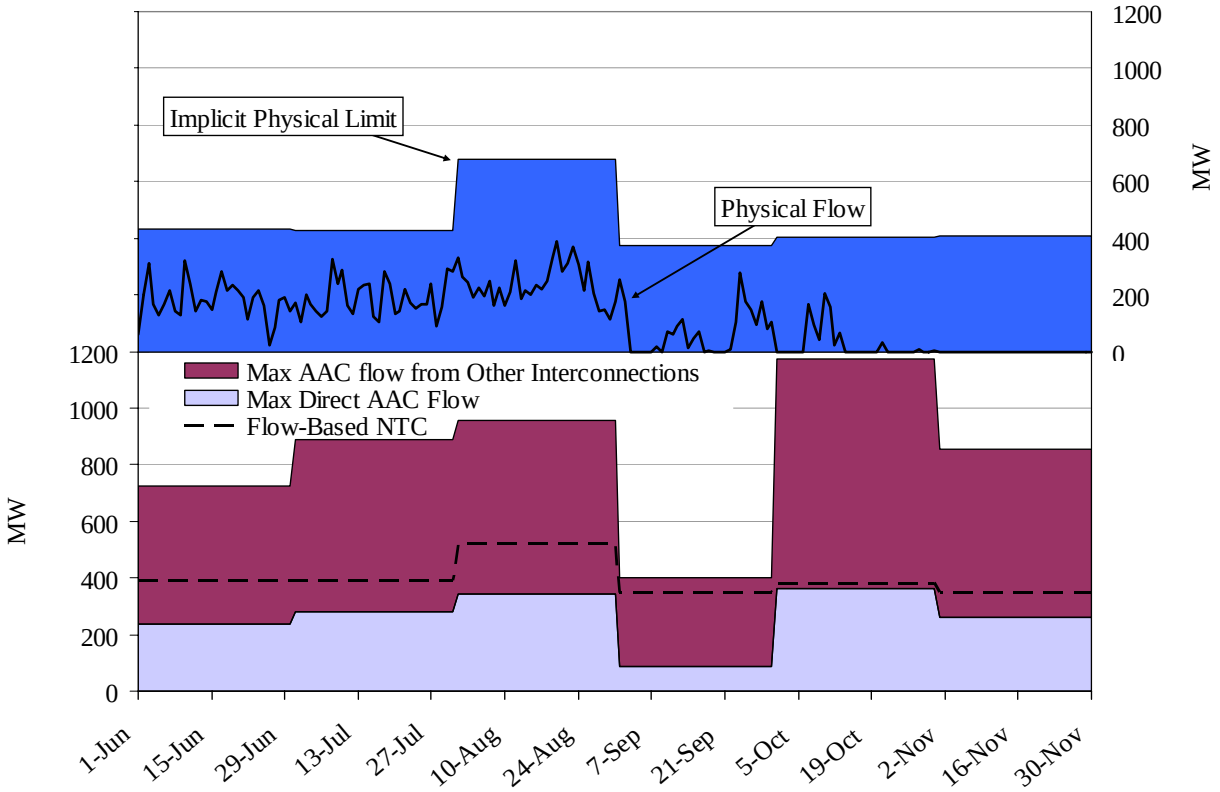



**Figure 14: Analysis of the Croatia-to-Serbia Interconnection**

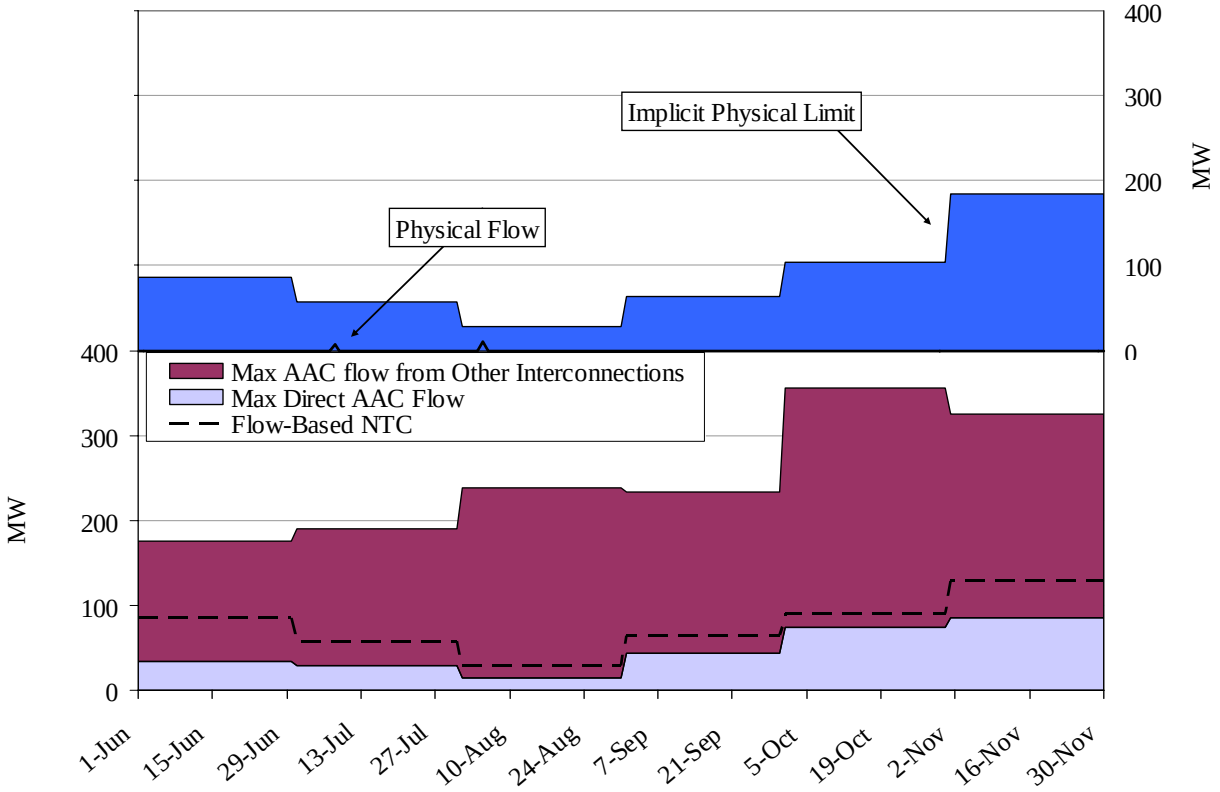


Figure 14 above shows the analysis of the Croatia to Serbia interconnection. This interconnection is relatively inactive. It has very little direct AAC and very little physical flow. The analysis does not indicate to us circumstances that give rise to efficiency or market concerns.

Figure 15 below shows the flows on the Macedonia to Serbia interconnection. Like the previous interconnection, this interconnection is relatively inactive. The reservations are small and are consistent with the minimal physical flow. Like most of the other interconnections, the potential for loopflow from other TSOs is substantial, although not evident by the physical flow data.

**Figure 15: Analysis of the Macedonia-to-Serbia Interconnection**

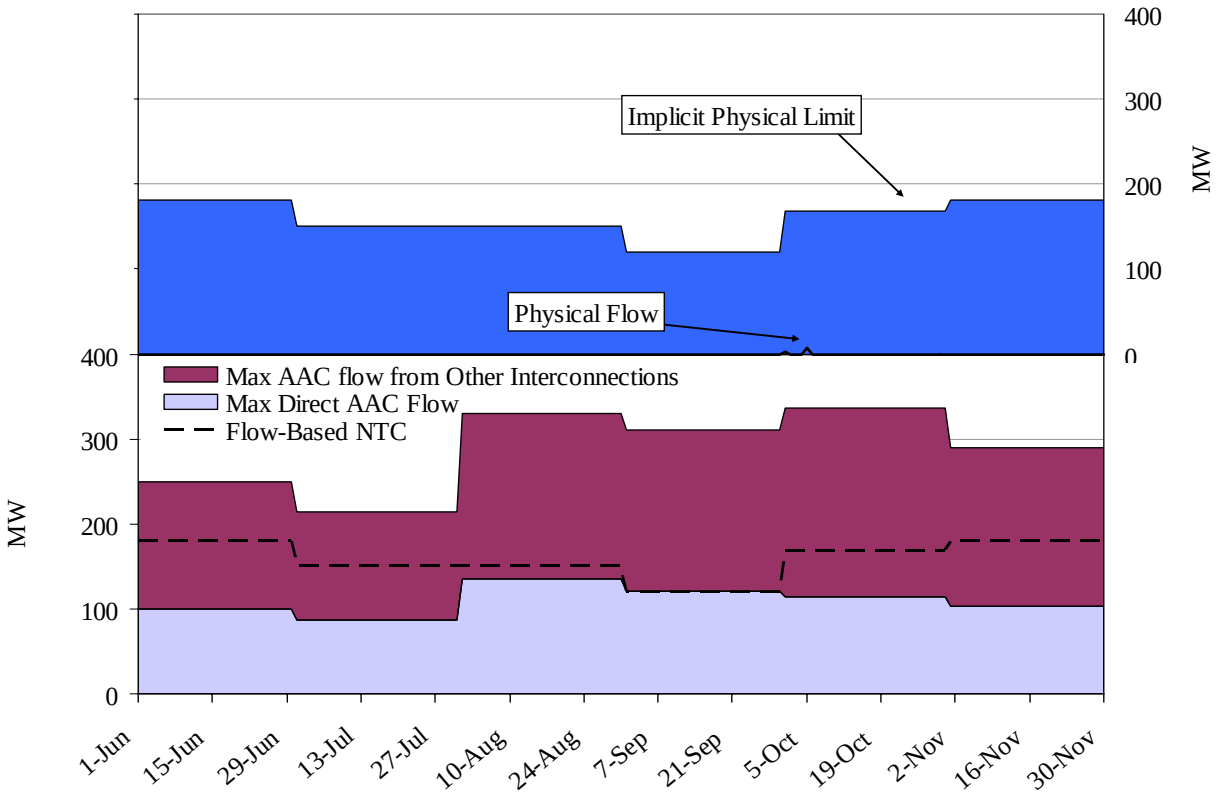


**Figure 16: Analysis of the Montenegro-to-Albania Interconnection**

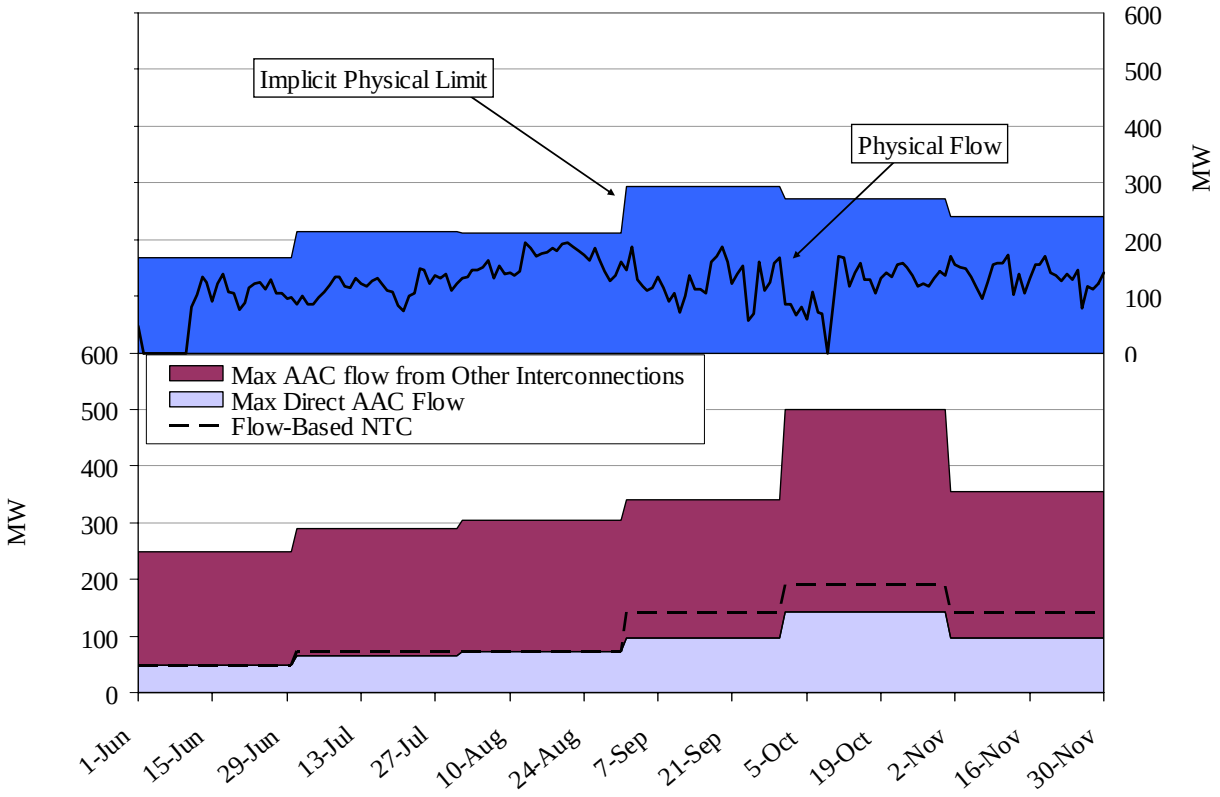



Figure 16 above shows the analysis of the Montenegro to Albania interconnection. It shows that over the time period, the ATC was zero or close to zero. The amount of physical flow associated with direct AAC is consistent with the actual physically flow data. The analysis does not indicate to us circumstances that give rise to competitive concerns.

The analysis of the Montenegro to Bosnia and Herzegovina interconnection is shown in Figure 17. This interconnection is relatively inactive -- there is not much capacity reserved, ATC is abundant, and there is also not much physical flow. We do not detect circumstances that give rise to competitive concerns on this interconnection.

**Figure 17: Analysis of the Montenegro-to-Bosnia & Herzegovina Interconnection**

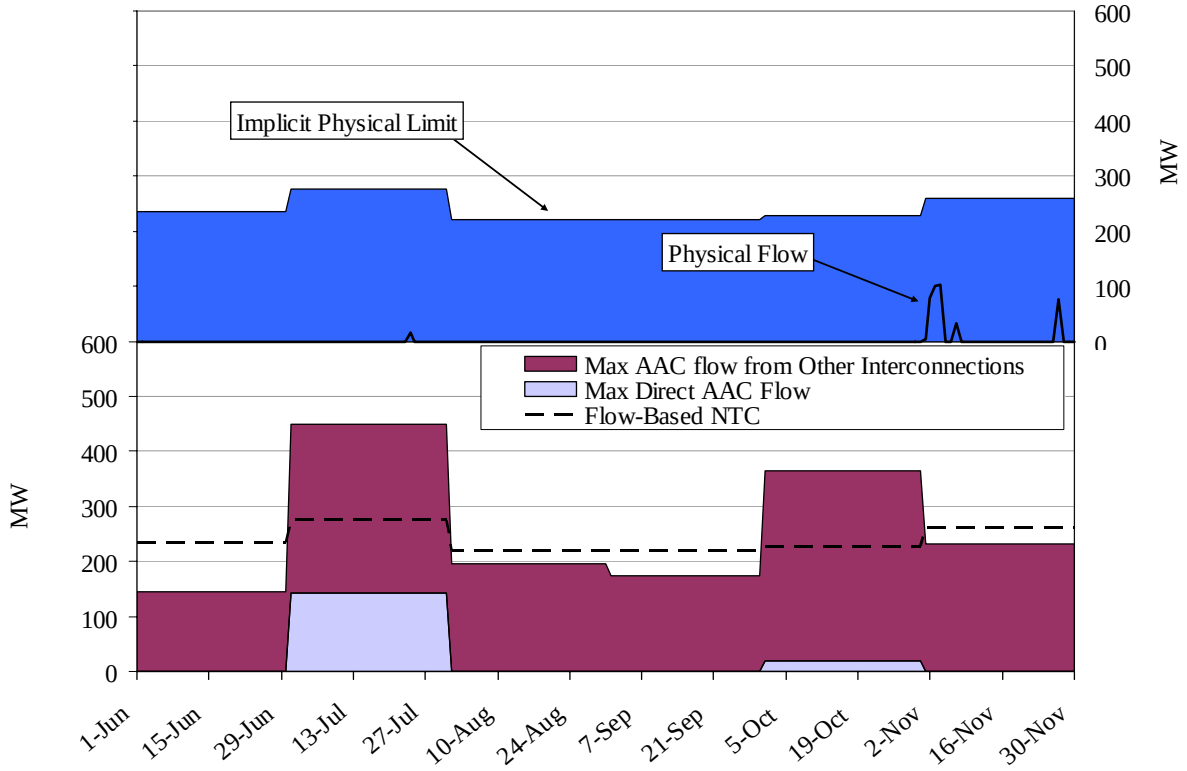



**Figure 18: Analysis of the Montenegro-to-Serbia Interconnection**

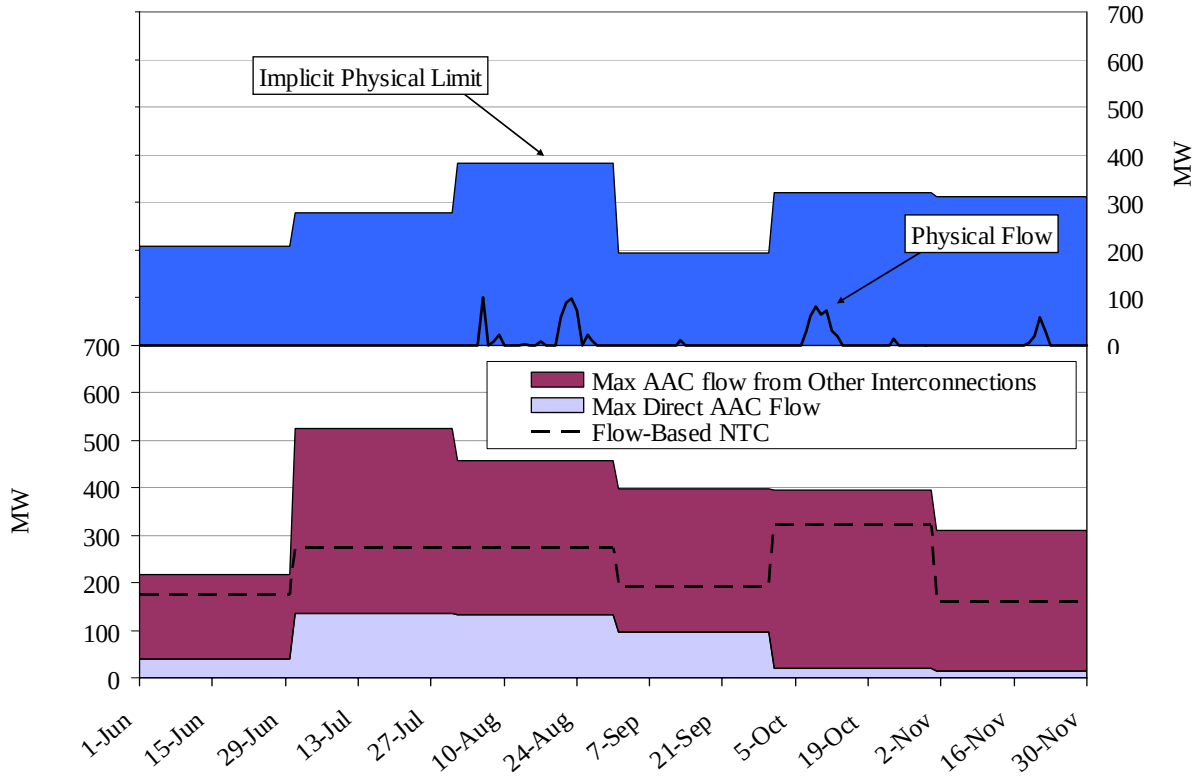


Figure 18 above shows the analysis of the Montenegro-to-Serbia interconnection. Like some others we have evaluated, there is not much activity on this interconnection. Reservations are small relative to overall NTC and physical flow is also minimal. We do not detect efficiency or market issues on this interconnection.

Figure 19 shows the analysis of the Romania-to-Bulgaria interconnection. This is a fairly active interconnection. Physical power flows extend up to 600 MW during the period studied. The capacity is fully reserved in all months, i.e., ATC is zero. However, the physical flows exceed the flows that would arise form the direct AAC. This provides an indication that the reservations are being used. Together with fact that the physical flow is often at or exceeding the physical limit, we conclude a larger NTC could result in greater utilization of the interconnection. However, our data is not sufficient to judge whether such possibility exists. Like the Bulgaria-to-Romania interconnection analyzed above, we estimated the AAC on this interconnection because Bulgaria does not make its ATC value readily available.

**Figure 19: Analysis of the Romania-to-Bulgaria Interconnection**

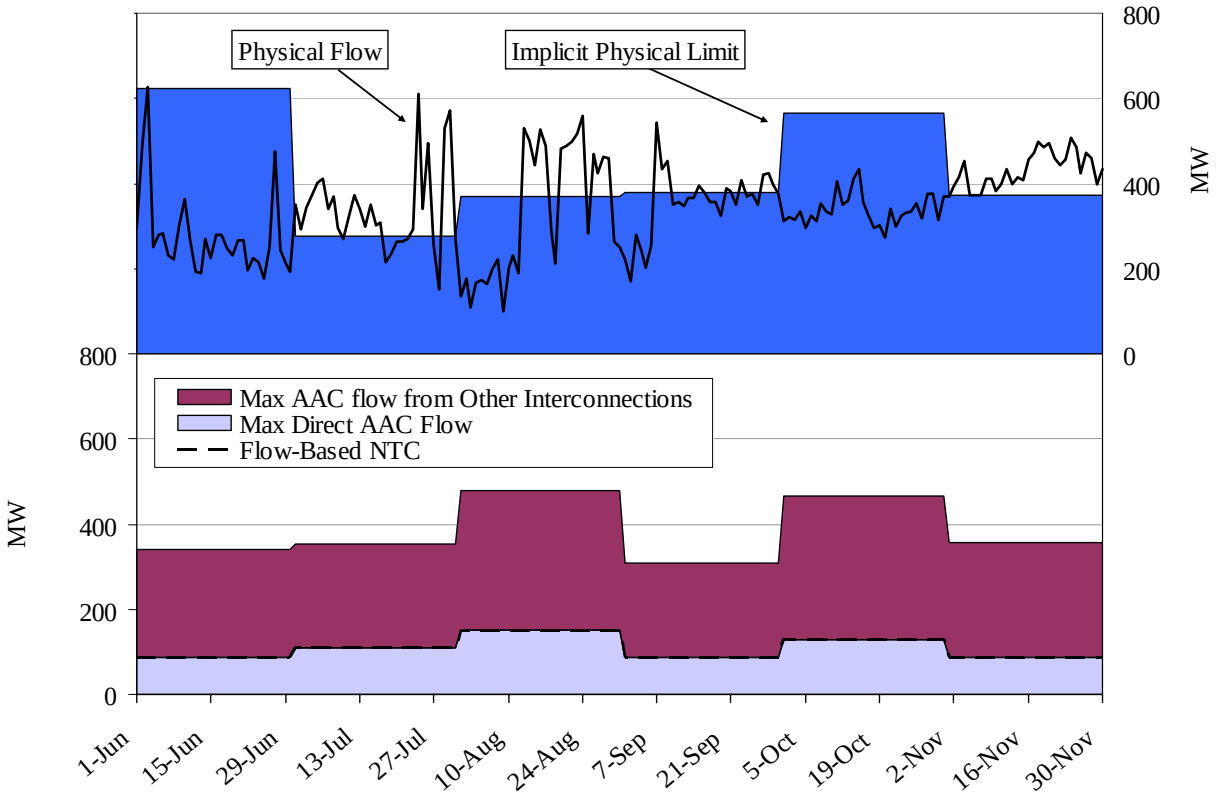


Figure 20 below shows the analysis of the Romania to Serbia interconnection. Like the Romania-to-Bulgaria interconnection, this interconnection is fully reserved and has large physical flows, often approaching physical limit. The physical flow slightly exceeds the maximum AAC flow (red-area plus the blue area) this could be the result of over scheduling or that in reality all AAC in this direction is actually scheduled.

Given the physical flows often approach the physical limit, precise estimates of the NTC is critical. This is an area of analysis that generally interests us and we are currently pursuing data to make it possible.

**Figure 20: Analysis of the Romania-to-Serbia Interconnection**

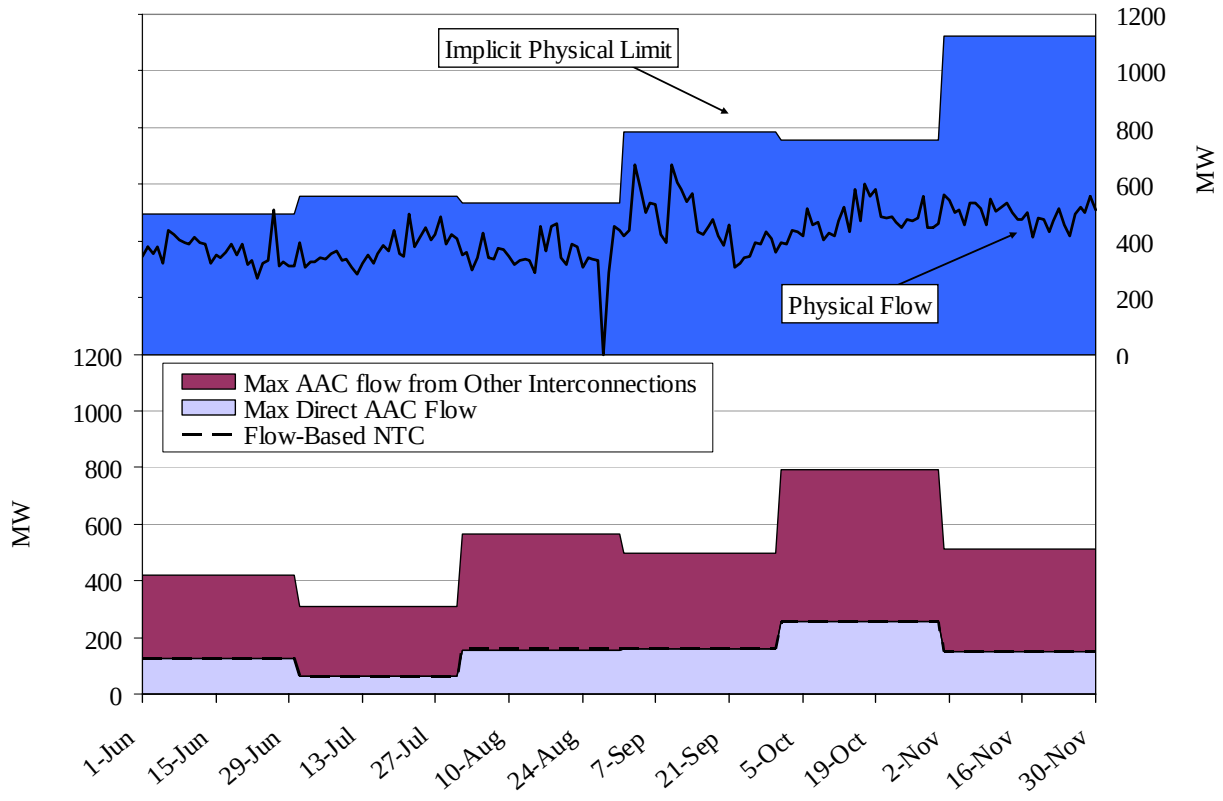



Figure 21 below shows the analysis of the Serbia-to-Albania interconnection. This interconnection is fully-reserved in all months shown. The physical flows are consistent with these direct reservations. Because the physical flows also approach the physical limit, additional NTC on this interconnection would likely contribute to increased efficiency.

**Figure 21: Analysis of the Serbia-to-Albania Interconnection**

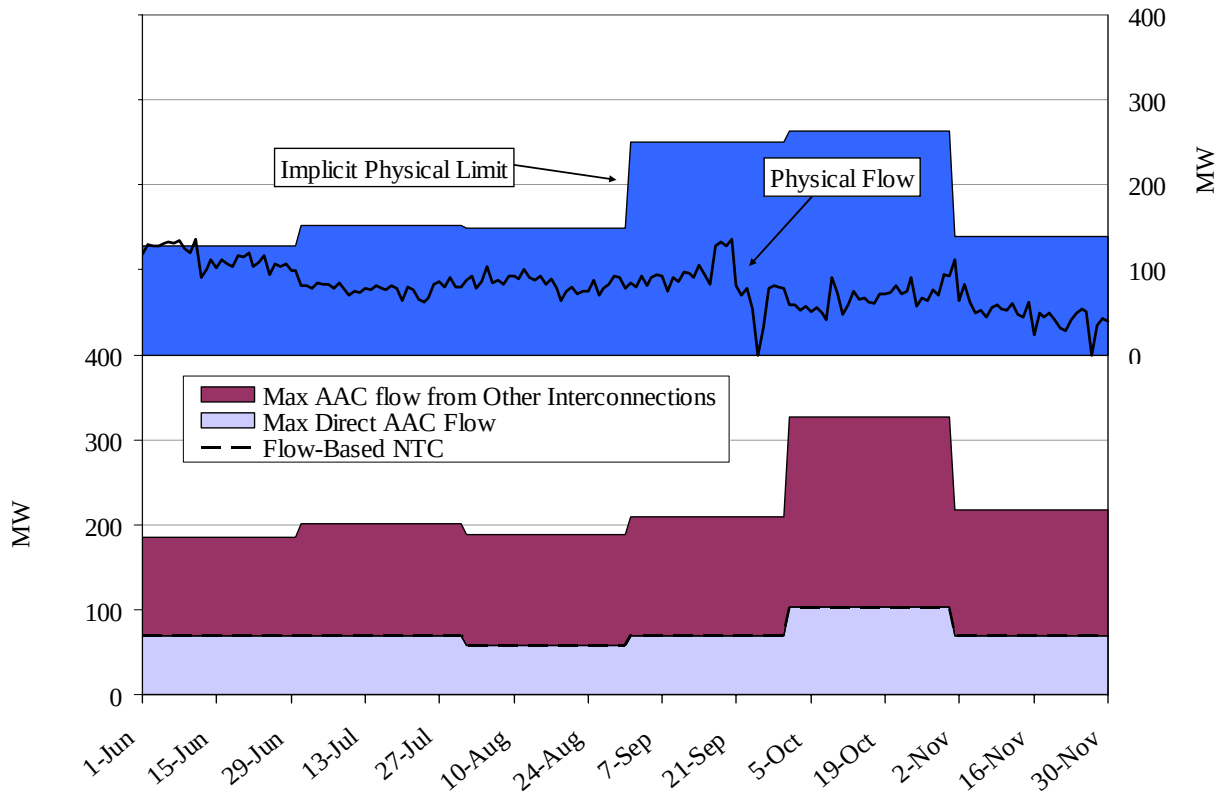



**Figure 22: Analysis of the Serbia-to-Bulgaria Interconnection**

<<Analysis was not possible due to lack of Serbia and Bulgaria data >>

Figure 23 below shows the Serbia-to-Bosnia & Herzegovina interconnection. As the lower panel shows, only small amounts of capacity are made available via NTC and ATC. However, large physical flows occur, even in excess of the maximum flow that would occur as a result of all AAC. Moreover, the physical flow exceeds the physical limit. It is possible that loopflow or other unexpected events have occurred over the period, but such contingencies would not support a sustained pattern as shown. One possibility is that additional physical flow is occurring from transactions that are not associated with AAC, either ones for internal dispatch or cross-border ones that are unscheduled. We seek further clarification on this the pattern of usage interconnection.

**Figure 23: Analysis of the Serbia-to-Bosnia & Herzegovina Interconnection**

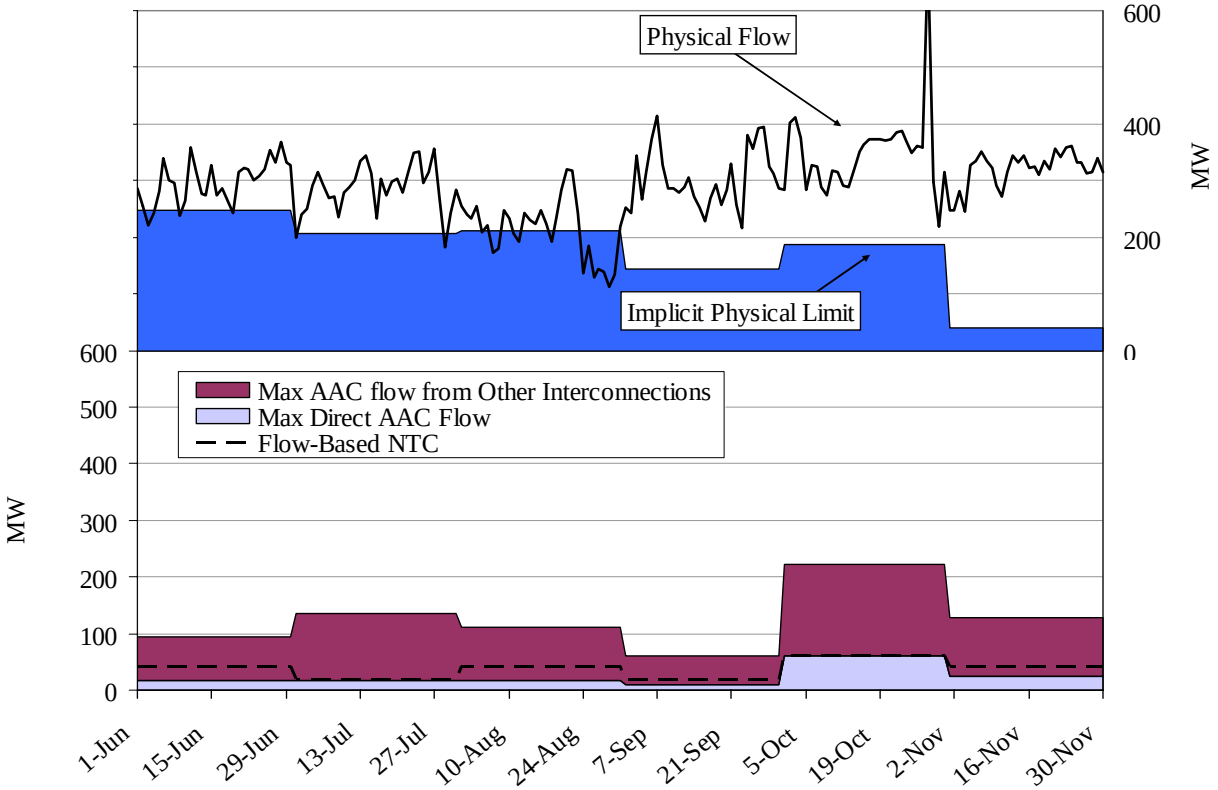



**Figure 24: Analysis of the Serbia-to-Croatia Interconnection**

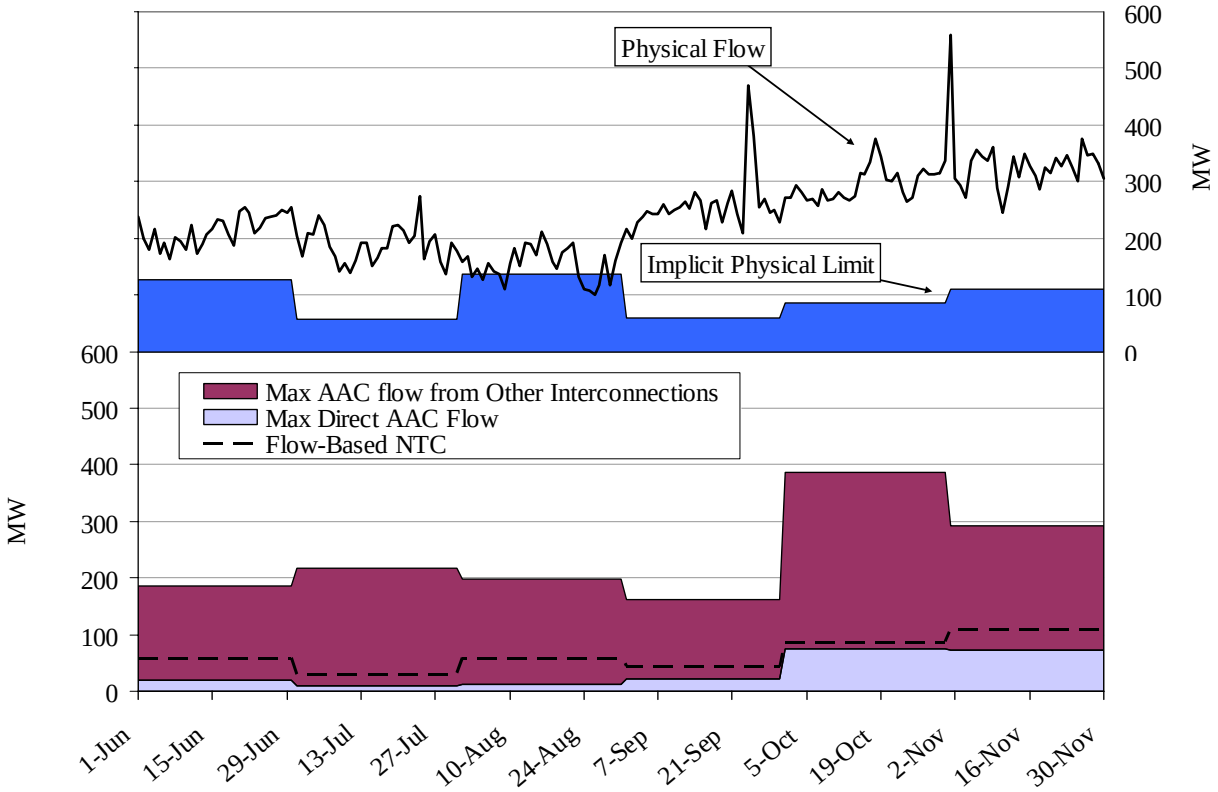


Figure 24 above shows the analysis of the Serbia-to-Croatia interconnection. As the lower panel of the figure shows, only a small amount of capacity is estimated to be available via NTC and this corresponds with a small amount reserved. However, large physical flows occupy the facilities and in some case are in excess of the maximum AAC flows (both direct and from other TSOs). Therefore, the physical flows must be the result of base case activity, either natural flows or base case exchanges. We did not have data from either Croatia or Serbia relating to natural flows or BCEs. We were able to estimate BCEs from the indicative winter 2007-2008 values and are comfortable we have accounted for that missing piece of information. We cannot produce a reasonable estimate of the base dispatch loopflow (i.e., the natural flows), so the analysis remains only partial. A large base case natural flow value in the direction of the interconnection could adequately explain what is observed. However, the point must remain unresolved for now.

If the circumstances do reflect large physical flows from other TSOs, then this is a case where substantial physical usage of the interconnection from others is occurring without compensation the parties to the interconnection.

Figure 25 below shows the analysis of the Serbia to Macedonia interconnection. As the lower panel shows, the NTC on this interconnection is fully reserved. The physical flows correspond reasonably well with the actual direct reservations. Because the physical flows approach and exceed the physical limit, careful analysis in estimating the NTC is called for. As indicated above, we seek ways to monitoring that process and are working to establish such analysis.

**Figure 25: Analysis of the Serbia-to-Macedonia Interconnection**

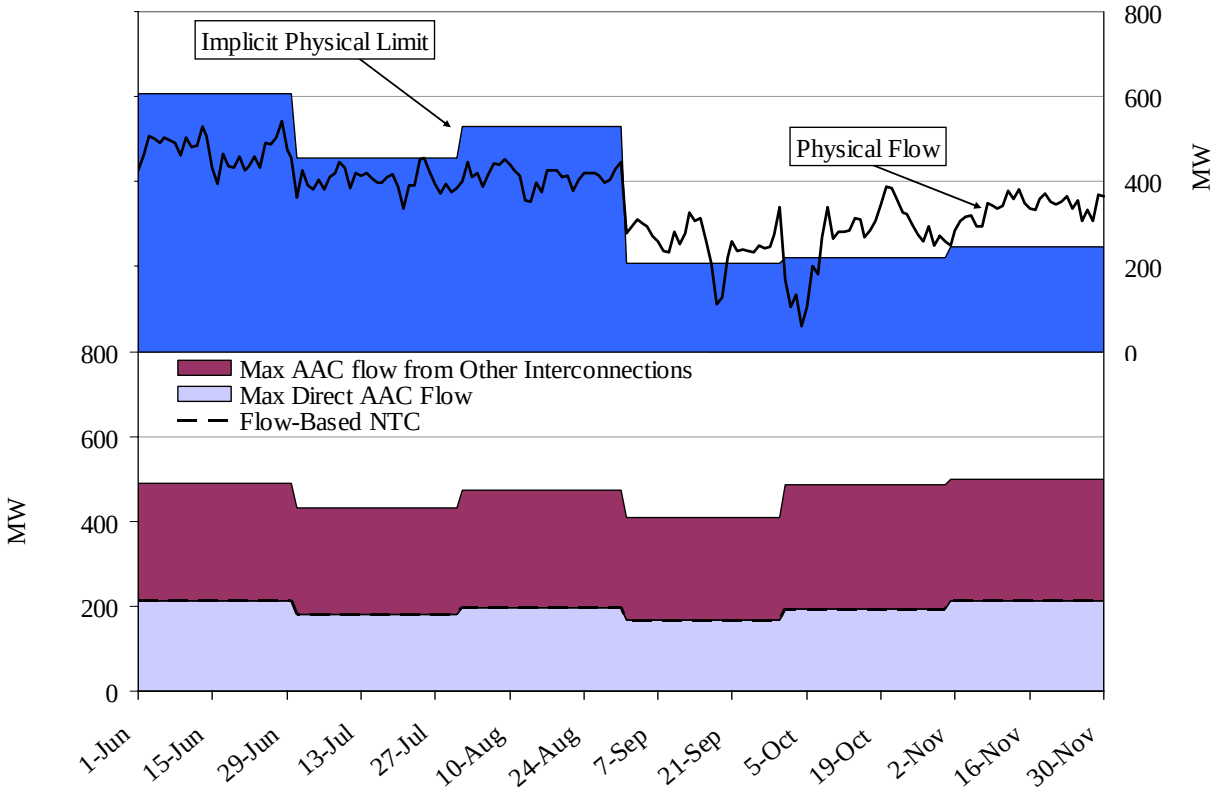



**Figure 26: Analysis of the Serbia-to-Montenegro Interconnection**

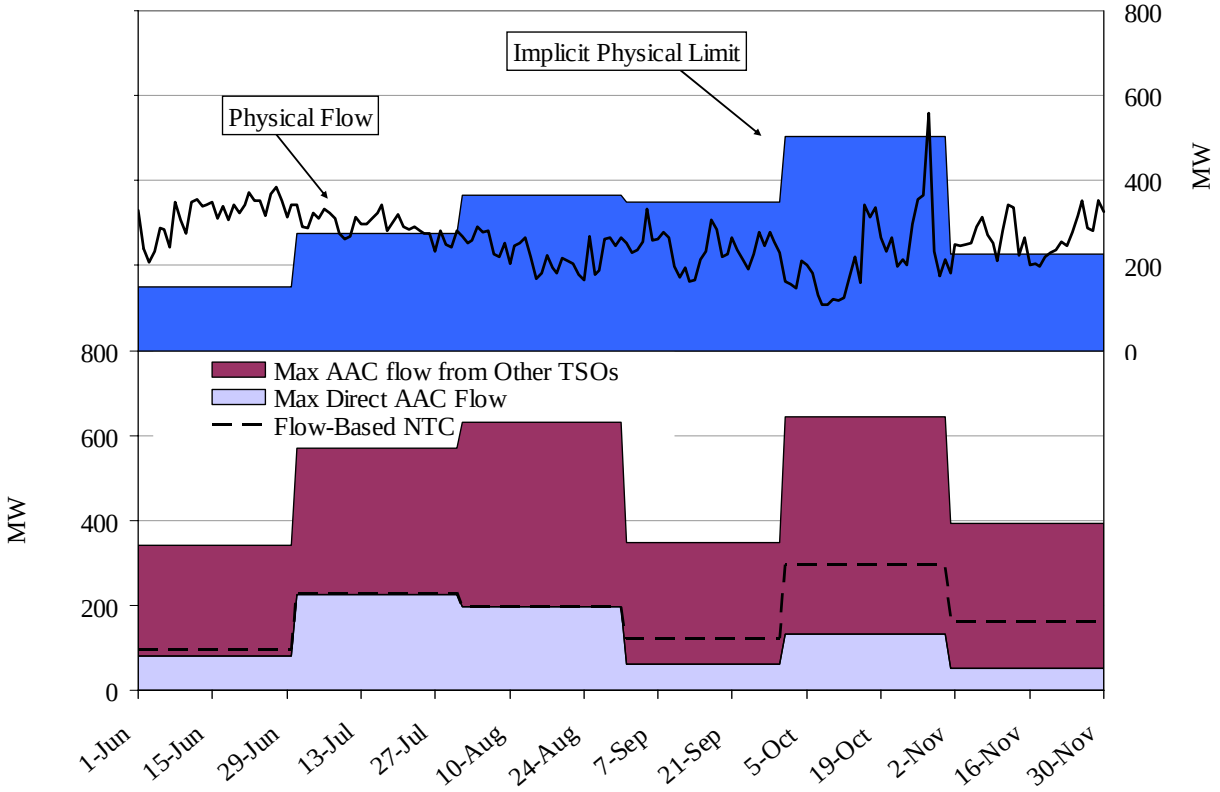


Figure 26 above shows the analysis of the Serbia-to-Montenegro interconnection. As the lower panel shows, the reservations on this interconnection vary somewhat, being higher in the summer than in the fall. The physical flows correspond reasonable well with the AAC. However, the physical flows sometimes exceed the physical limit, which suggests a careful estimating of the NTC values. Otherwise, the analysis does not indicate to us circumstances that give rise to competitive concerns.

**Figure 27: Analysis of the Serbia-to-Romania Interconnection**

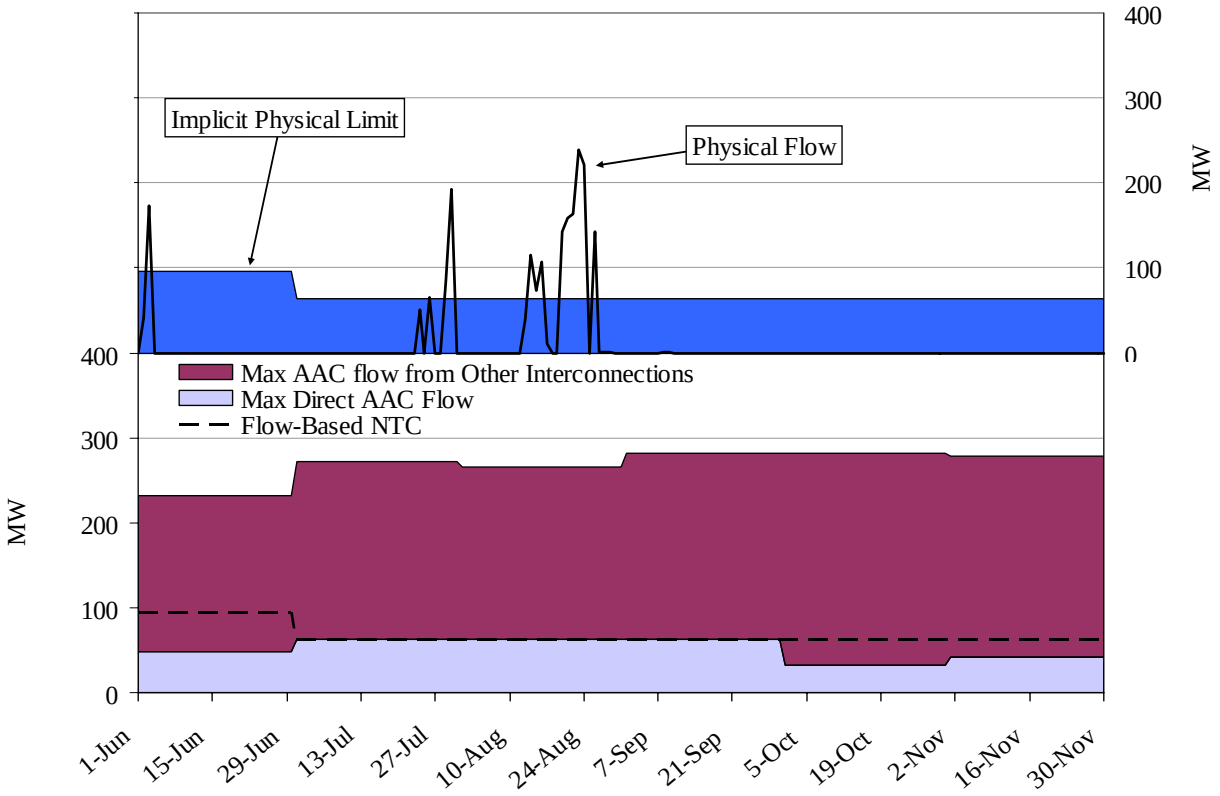



Figure 27 shows the analysis for the Serbia to Romania interconnection. This is a relatively inactive interconnection. Most activity is in the opposite direction (see Figure 20). Very little is reserved on this interconnection and there are very little flows. We do note the individual instances where power transfers peaked above the physical limit. This warrants further monitoring. Otherwise, the analysis does not indicate to us circumstances that give rise to efficiency concerns.

*Summary of Interconnection Capacity Analysis.* Overall, we find in many instances the actual physical usage to be consistent with physical usage associated with reservations. However, in

some case, as noted, certain questions arise as a result of the pattern of reservation and usage. We anticipate taking up these issues with the parties involved to achieve a greater understanding of the issues.

## V. WHOLESALE NETWORK MODELING[20]

### A. Background

The objective in the Phase II of the Pilot Plan with respect to the generation markets was to further improve the wholesale electricity generation model developed for the region during Phase I. We have done so by updating the input data according to the latest cost and capacity estimates available to us, and also by extending the previous version of the SEE model to include the effect of countries neighboring the region and by explicitly accounting for the cross-border constraints on commercial trade within the SEE region.[21]

The structure of this section of the report is as follows. In the next subsection (subsection B), we will describe the simplifying assumptions behind and the workings of the market model in a non-technical manner. In subsection C, we give an overview of the input data regarding the composition of the supply and demand side of the region, the transmission constraints, and the assumed price conditions outside the SEE region. In subsection D, we present and discuss the results of the model base scenario. In subsections E and F, we evaluate the effect of changes in cross-border trading opportunities and discuss the possible motivation and ability of generation companies to exercise market power. In subsections G and H, we examine the consequences of changes in the region's nuclear portfolio and address the question of unit derating and associated price effects. In the last subsection, subsection 0, we draw preliminary conclusions from the modeling exercise, stress the limitations of the applied modeling approach, and suggest some directions for further investigation.

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20 The section was produced and written by REKK. We are in the process of procuring additional data for the model. Because the model has not changed significantly since the last report, this section has not been changed. It is included for the convenience of the reader.

21 For an initial assessment of the SEE region and for the motivation behind and general caveats of market simulations, please refer to the Phase I predecessor of the present study "Wholesale generation market monitoring and market simulation".

## B. The SEE model

As indicated above, our modeling approach is a competitive benchmark analysis. That is, we will simulate the efficient market outcome in the SEE region given the supply and demand characteristics and the constraints on cross-border trade. We consider this approach to be a good starting point because it describes the most desirable outcome possible (from an economic point of view) and thus provides an ideal and unique benchmark, to which actual observations can be compared.

Our main simplification is that we assume a separate, fully liberalized wholesale electricity market in each part of the SEE region, operating either as a centralized pool, as a sufficiently liquid bilateral market, or as a combination of the two. In these markets, both sellers (generators, traders) and buyers (traders, supply companies, large consumers) are price-takers. This means that every actor in the market decides upon his or her optimal action (how much to generate?, how much to consume?) based on the prevailing market price and believes that whatever the optimal action may be, it will have absolutely no effect on the market price.

With this simplifying assumption in mind, we will model the demand side in an aggregate way: in each market, there will be a single demand function describing how much electricity people choose to consume at given prices.

The supply side will consist of generating units that operate within a given market. As our objective is to model short run competition, we will only take into account short run variable (i.e. fuel) costs. We will assume that these costs vary linearly with the level of production, implying that the marginal costs of power generation are constant for a given unit.

When this is the case, a price-taking generator has a very simple choice to make. If the prevailing market price is above its own fuel costs, then the unit will be operated at full capacity. Conversely, when the market price does not cover the fuel cost, the unit will be shut down.[22]

Cross-border electricity trade will be limited by the capacity of the interconnection between any

[22] It may also be the case that the two are equal. In that case the generation company is willing to produce at any capacity level, since short run profits are always zero.

two markets. As we are in a completely liberalized setup,[23] the proper measure of cross-border capacity is the Net Transfer Capacity (NTC), which is the maximum amount of electricity that can be routed commercially across the border. We assume that efficiently organized bilateral (or coordinated) auctions take place at the border, meaning that cross-border trade between any two markets will keep increasing as long as (1) there is still a price difference between the two markets, and (2) not all the NTC is utilized and there is no congestion at the border. The auction revenues will always be equal to the price difference between the two corresponding markets multiplied by the amount of electricity traded across the market boundary.

Countries neighboring the SEE region will be treated somewhat differently from SEE markets. In these countries, we assume that traders can buy or sell electricity in any amount at pre-specified, fixed prices, as specified below. In effect, we are saying that these outside countries are either large enough relative to the available cross-border capacity, or are integrated well enough into a much larger outside region, so that cross-border trade not to have any effect on their internal market prices. As a result, markets on the edge of the SEE region will export electricity outside the region whenever the outside price is relatively high, and will import in the opposite case. Again, NTC values will limit the amount of feasible exports and imports.

The equilibrium outcome of the model will be characterized by a set of market prices such that in each regional market, the amount of electricity supplied to the market (either generated or imported) will be equal to the amount of electricity used (either consumed or exported) at the market price. Economic theory tells us that this competitive equilibrium will be efficient in the sense that it generates the highest overall welfare in the combined electricity markets.

## C. Input data description

The wholesale market model needs four different types of input data: electricity supply costs and capacities by location, demand characteristics by location, constraints on cross-border electricity trade, and price levels outside the SEE region. We will describe each of these in turn.

[23] This means all capacity is available for trade and none is “grandfathered” for uneconomic trades.

### 1. Electricity supply

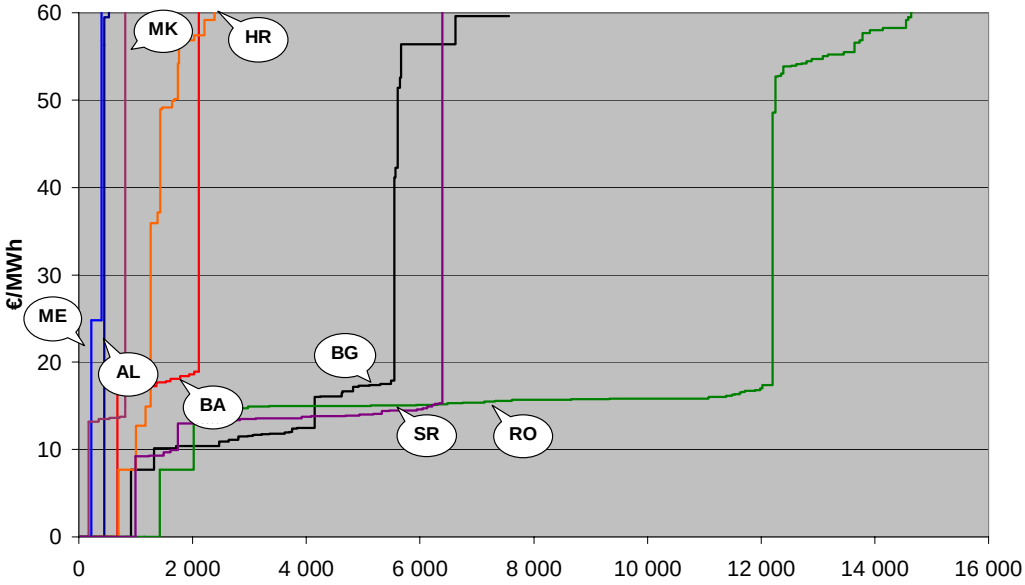
The marginal costs of electricity generation are identified with the cost of fuel used in the plants, which are likely to make up the largest portion of real marginal costs. Variable operating expenditures, which are typically a small of variable costs, are not taken into account, and neither are start-up costs or any variation in heat rates at different capacity usage levels. We assume that all plants in the region are capable of generating electricity up to their available capacity (taken to be around 90-95 percent of installed capacity for thermal plants and one-third of installed capacity for hydro generation).[24] We do not take into account reserve requirements and estimate heat rates based on plant type and age.[25]

Based on this method, we get the country-by-country estimated merit order curves (supply functions) of the SEE region depicted in Figure 28.

[24] In effect, we are limiting the electricity production of hydro power plants to correspond to year-round average levels. In case of run-of-river plants, we believe this to be a reasonable assumption, whereas in the case of HPP's with sufficient storage, we are probably being overly cautious – after all, peak demand conditions do not prevail around the clock, meaning that storage plants could easily be run at higher capacity usage levels during the peak hours.

[25] Applied heat rates are taken from: KEMA Consulting, "Analysis of the network capacities and possible congestion of the electricity transmission networks within the accession countries", study commissioned by the European Commission, Directorate-General Energy and Transport, v. 1.3, June 2005. Fuel cost estimation was based on the latest updated (2006) information available to us from the South East Europe Generation Investment Study by the World Bank. More details about the cost estimation procedure (for a different, but overlapping region) are given in Kiss-Barquín-Vázquez, "Can Closer Integration Mitigate Market Power? – A Numerical Modeling Exercise", study of the Central and Eastern European Energy Market (C3EM) research project by REKK, July 2006.

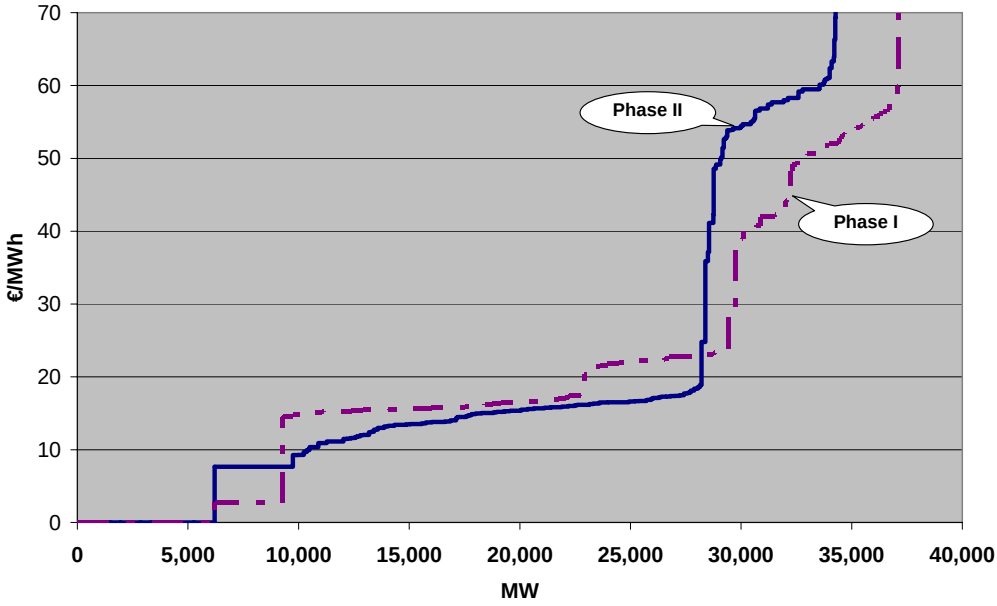
**Figure 28: Estimated Merit Order for each Market**




*Note*: Abbreviations are as follows: Albania (AL), Bosnia and Herzegovina (BA), Bulgaria (BG), Croatia (HR), Montenegro (ME), Macedonia (MK), Romania (RO), Serbia (SR).
*Source*: KEMA 2005, World Bank 2004 and 2006, own calculations.

We aggregate these supply functions into a single, regional merit order curve, as shown in Figure 29. The figure also shows how the regional merit order has changed from our previous Phase I estimate.

**Figure 29: Estimated Merit order for the SEE Region**




Since we assume price taking behavior from all market participants (meaning that they are

willing to generate electricity whenever they observe a market price that at least covers their marginal costs), we can freely disregard the actual ownership structure of power plants as it does not matter from the point of view production decisions. The main changes vis-à-vis our Phase I estimations have been a marked decrease in coal-based generation costs (due to a switch of fuel data sources to the GIS) and an equally visible cost increase for gas-fired generation (mainly attributable to the latest developments in hydrocarbon world markets).

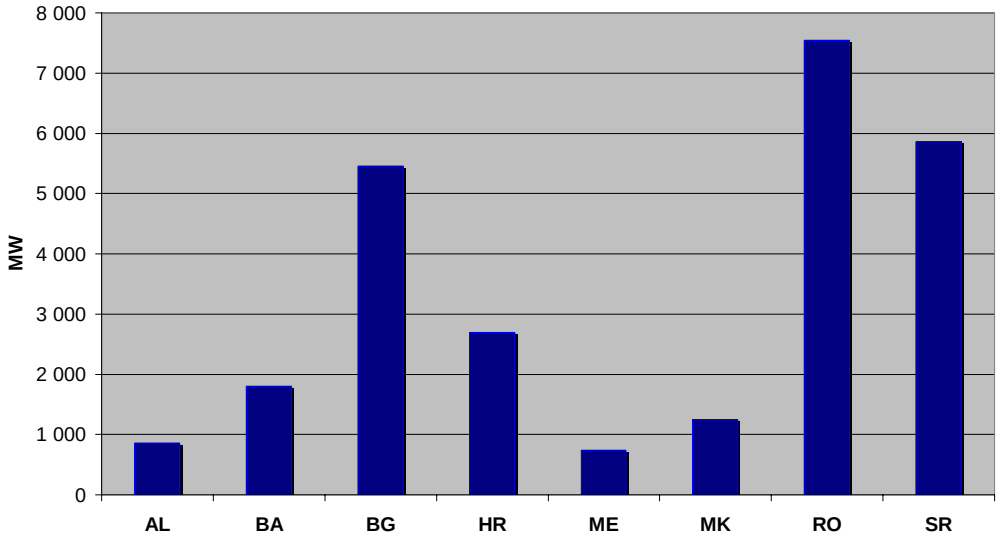
### 2. Electricity demand

Generally, consumer demand for any product is inversely dependent on its price: the higher the price, the less people want to buy. The sensitivity of demand to price changes is influenced by many factors, among them the substitutability of the product, the time interval considered, or the necessity for people of consuming (using) the product. Regarding a short-term electricity markets without real-time metering for most consumers, we can expect this sensitivity (the price elasticity of demand) to be very low. In the extreme case (applied in the Phase I modeling example), we can take the price elasticity to be zero, meaning that electricity demand is the same no matter what the equilibrium price turns out to be.

In the base scenario of the SEE model, we assume that short run demand is barely responsive to price changes and take an “educated guess” regarding the price elasticity factor (-0.1). This means that it takes approximately 10 percent increases in the price level for people to reduce their consumption by 1 percent. The price-quantity relationship will be captured by a linear functional form.

Peak loads are derived from observed high consumption periods during January 2006 (off-peak demand will be considered as one half of the peak load). Aggregated demand for the region is simply the sum of the individual market demands. Figure 30 shows the peak demand scenario that we consider for this example.

**Figure 30: Estimated Peak Demand for each Market**

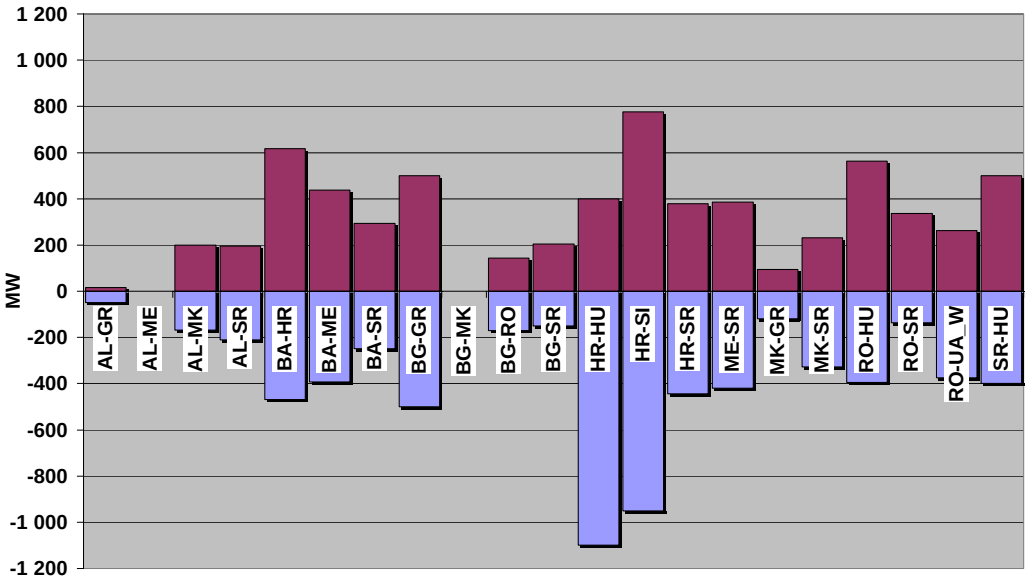



*Source*: UCTE, SEETEC

### 3. Transmission constraints

We use average NTC values for the first half of 2007 from/to regional markets. In some cases, where data was not available, we had to extrapolate from other information sources. Positive values are limits in the direction of the interconnection notation (e.g. in the case of BA-HR: from BA to HR), whereas negative values are limits in the opposite direction. The two magnitudes usually correspond to each other, although some cases (e.g. HR-HU or RO-SR) do break the pattern.

**Figure 31: Average Monthly NTC Values in the SEE Region for 2007/I.**




*Source*: ETSO, Potomac Economics, own calculations

### 4. Price levels in neighboring countries

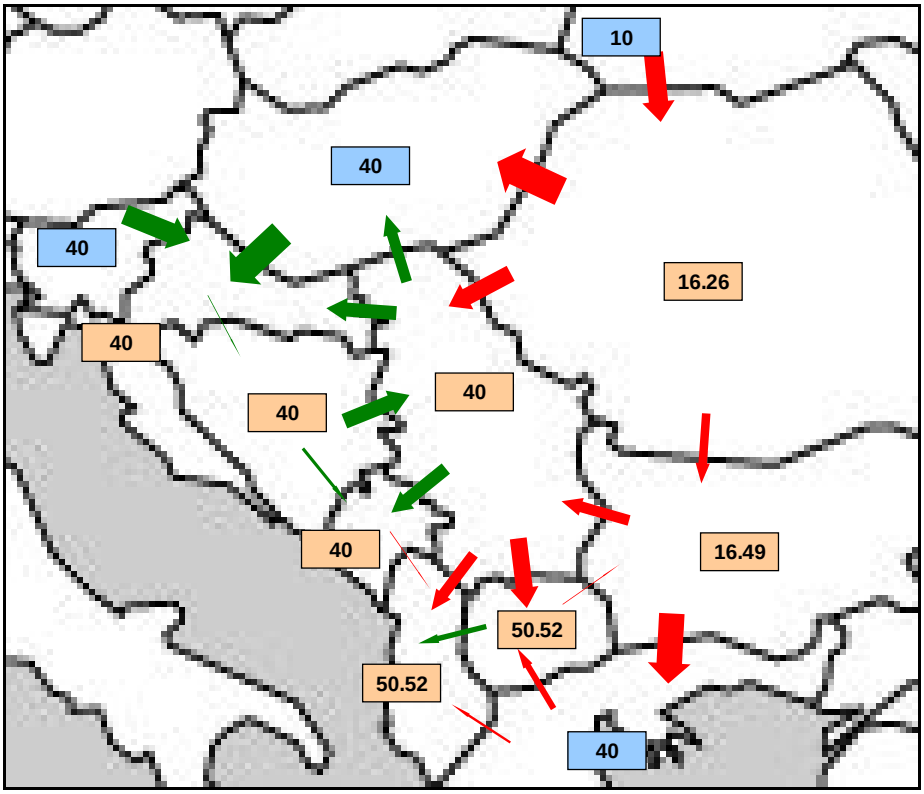
In the base scenario of the model, we will only distinguish between a low price neighbor, West Ukraine (UA_W) with 10 €/MWh, and three higher price neighbors, Greece (GR), Hungary (HU), and Slovenia (SI) with 40 €/MWh. We should note that these prices are simply assumed in the model, and do not come from any particular market data source. Our main intention was to have Ukraine act as an exporter into the SEE region (thus the very low price), and to be in a broadly realistic price range for the other three countries. It turns out that price assumptions about Ukraine and Greece are innocuous (as a result of their weak links to the region). On the other hand, we will see that prices in Hungary and Slovenia will drive many of our results.

## D. Base Scenario Results

Results of the model simulation for the base scenario are shown in Figure 32. The map of SEE and neighboring countries has been partitioned according to the international boundaries. Within each country, the equilibrium price is displayed within a corresponding rectangle (in €/MWh). The prices with blue backgrounds have been exogenously given, since they belong to

neighboring countries. The prices with a peach-colored background (for SEE countries) have been calculated as part of the market equilibrium.

**Figure 32: Base Scenario Results**




On each interconnection, there are arrows showing the direction and volume of cross-border trade. The width of the arrow is proportional to the amount of trade that takes place between two markets. As a reference, the capacity used between Bulgaria and Greece is exactly 500 MW.

The color of the arrows is also of significance. Red-colored arrows indicate congestion on the border (all capacity is used); whereas the green color signals that still more trade is possible on the interconnection. As expected, when any two countries are connected with a green arrow on some (not necessarily direct!) route, their market prices are equal.[26]

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26 We need to make important clarifying remark at this point regarding trade patterns in non-congested sub-regions. When several neighboring markets have the same market price and they can trade with each other via different routes (directly, or through third countries), then the market model does not determine the non-congested trade patterns uniquely. No congestion means no interconnection fee, which means that trade via

Conversely, when two or more countries (groups of markets) are only joined with congested lines, we can expect their market prices to diverge. In that case, the assumption of efficient cross-border capacity auctions implies that the price difference (the potential profit from trade) will be bid away on the auction, and will thus be captured as auction revenue by the TSOs involved. (We assume that auction revenues are shared equally by the TSOs at the two ends of the interconnection.)

The base analysis offers the following lessons regarding the base scenario market equilibrium.

- Both Romania and Bulgaria are low-cost net exporters with congested borders, even between themselves.
- There is a high price congested sub-region consisting of Albania and Macedonia, due to their insufficient internal generation capacity and relatively weak outside connections.
- Much of the central and western part of the SEE region is non-congested, although still a net importer from Hungary and Slovenia. As a result, market prices in this sub-region are driven by the outside ("northwestern") prices prevailing in the neighboring countries.
- A few model runs confirm that this price alignment of the central and western part of the SEE region to the northwest holds true for quite a wide range of Hungarian and Slovenian market prices: from 25 €/MWh to 83 €/MWh in the base scenario settings. Obviously, once the northwestern price rises above 50.52 €/MWh, Albania and Macedonia also join this sub-region.
- It is also worth noting that the SEE region in the base scenario is a *net importer* from Hungary and Slovenia when the northwestern price is below 59 €/MWh, but it becomes a *net exporter* to the northwest above 59 €/MWh.

## E. The Effect of Trade Constraints

According to our data, NTC values on interconnections vary widely even from month to month. On average, cross-border capacity can change ±40-50 percent relative to our baseline values,

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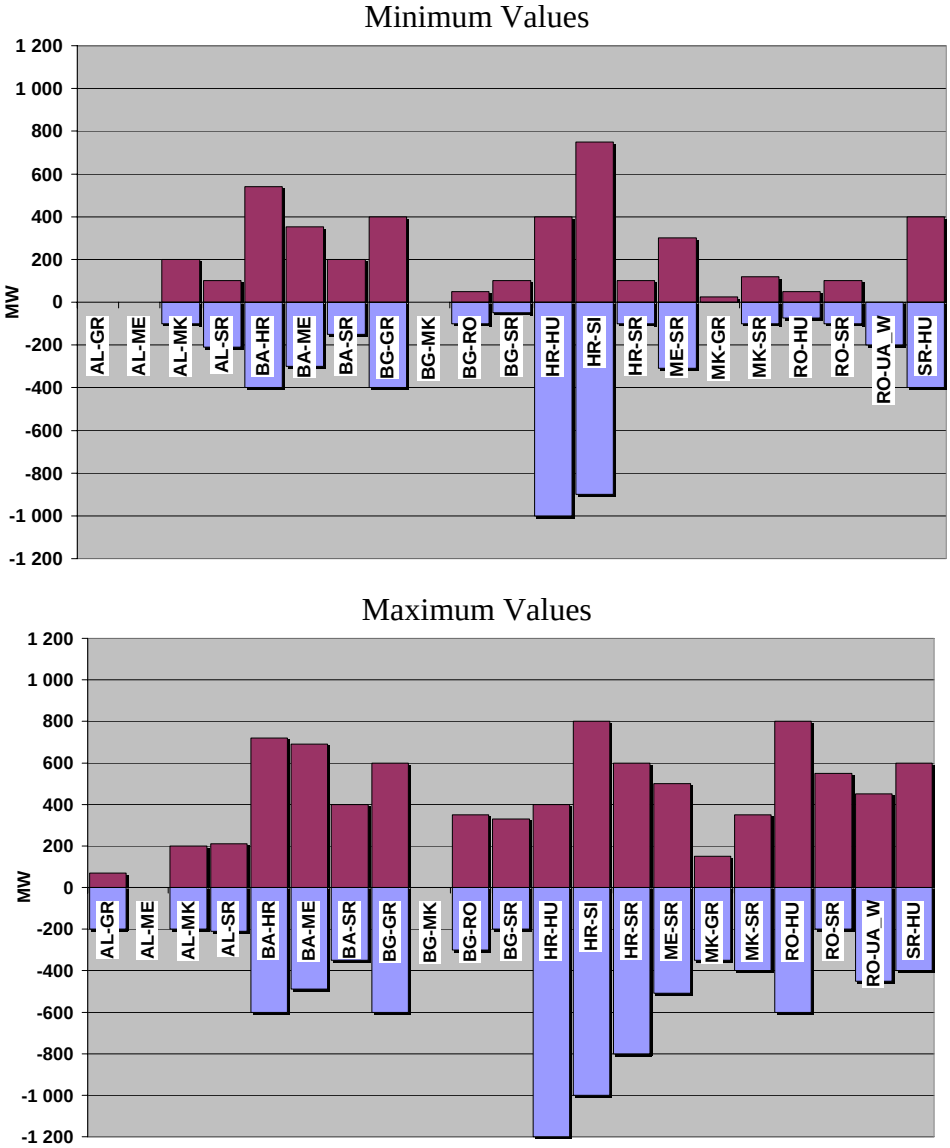
any parallel route is equally costless. The model simply selects one equilibrium trade pattern within the non-congested sub-region randomly.

which we can expect to have considerable effects on the market equilibria across the SEE region.

In this section, we will examine three additional scenarios. In the first, as an absolute benchmark, we will set all cross-border capacities to zero, in effect denying all possibilities for electricity trade. This is the case where we expect to see the largest disparities in individual market prices: naturally, each market will be cut off from its neighbors and will have to rely on local generation capacity to fulfill all demand. In the second and third scenarios, we will use the lowest and highest NTC values observed in the first half of 2007 in the SEE region. This range of NTC values is shown in Figure 33.

**Figure 33: Minimum and Maximum NTC Values**




*Source*: ETSO, Potomac Economics, own calculations

We estimated three scenarios, one with no NTC constraints; one using Minimum NTC values; and one using Maximum NTC values. The results from each trade capacity scenario are shown in the following figures.

**Figure 34: Market Equilibrium Prices with No NTC Constraints**

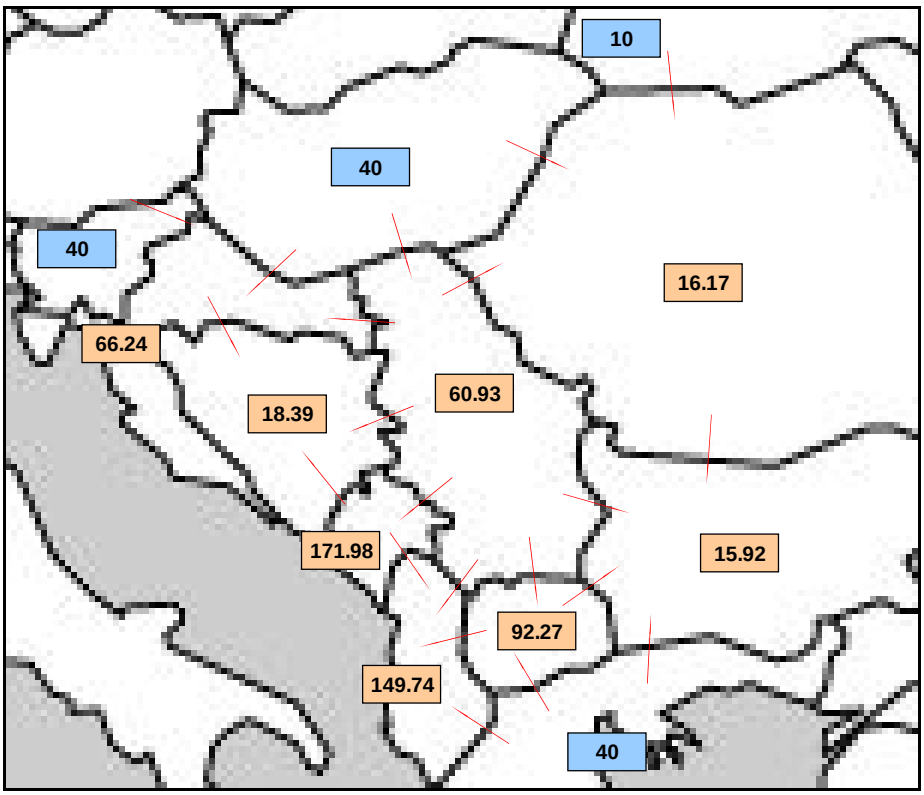


**Figure 35: Market Price Equilibrium using Positive NTC Values**

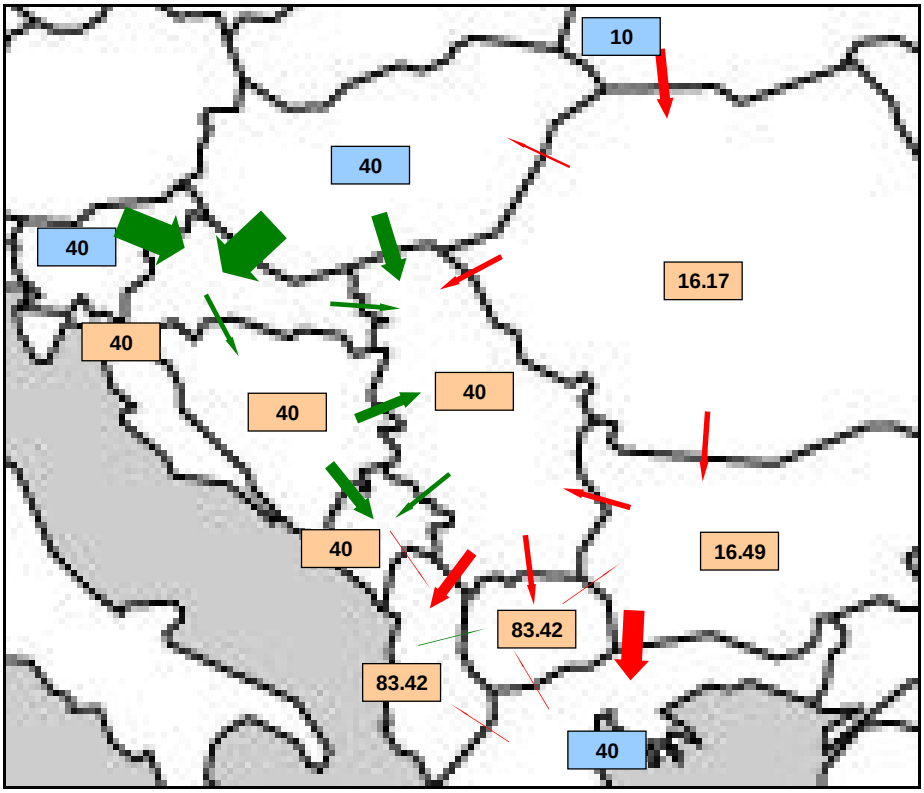
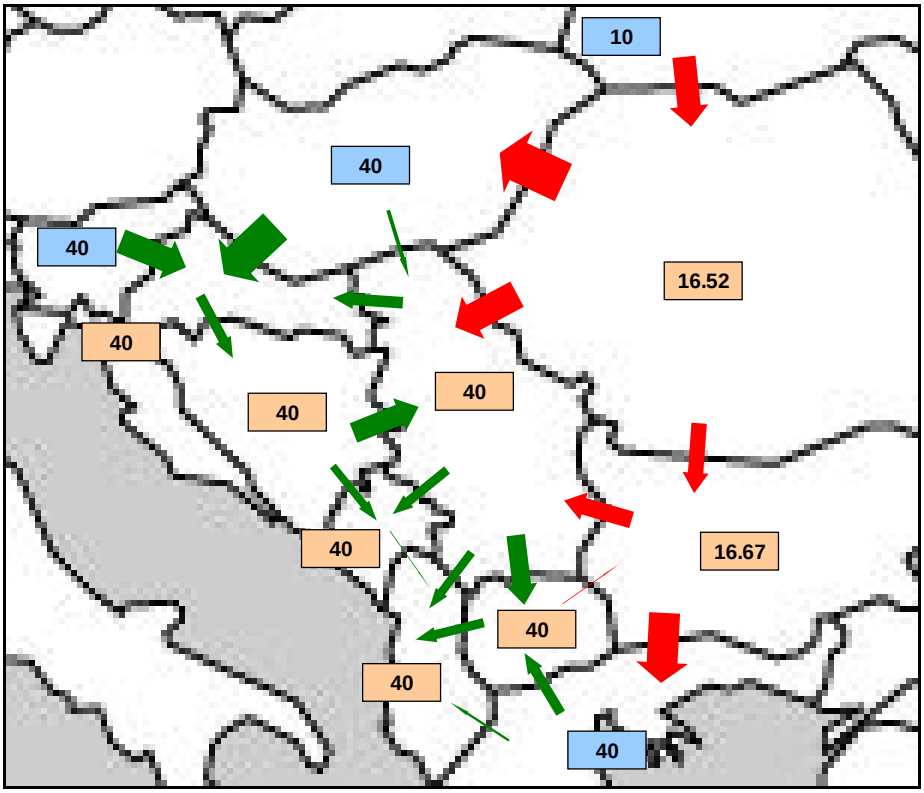


**Figure 36: Market Equilibrium Prices using Highest NTC Values**




Based on the model runs, the following lessons seem to emerge regarding the effect of trade constraints on the SEE market equilibrium:

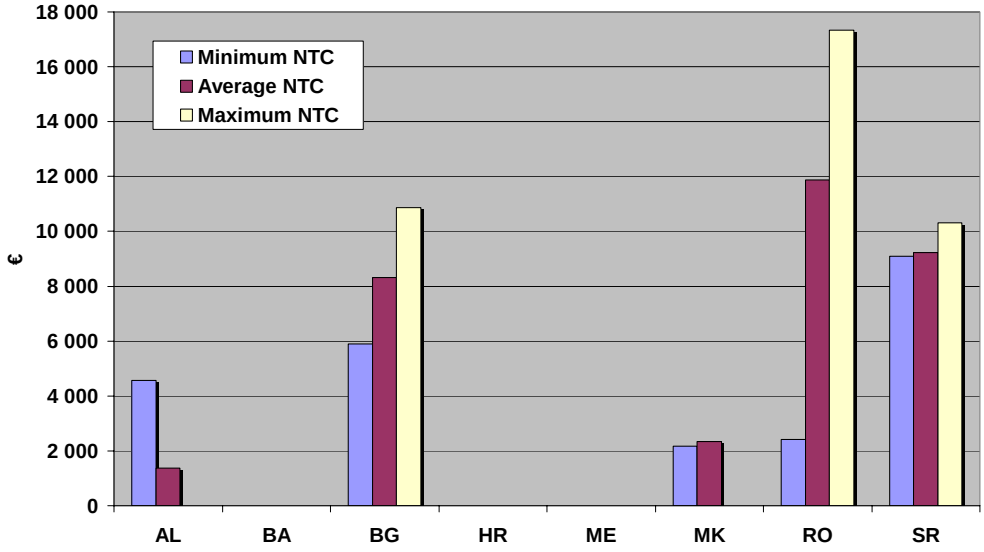
- Market prices in the two large net exporting countries, Bulgaria and Romania, are basically not affected by trade restrictions. This result is not straightforward: it could be the case that the rest of the SEE region exerts a strong enough upwards pull on the internal prices of these two markets. But, in fact, it does not.
- The No NTC constraint scenario yields extremely high prices in some markets that are normally strongly dependent on net exports to fulfill domestic demand. The high price sub-region lies in the southern part of SEE (AL, ME, MK), but to some extent the Croatian and Serbian markets are also affected by the lack of trade. On the other hand, the BA market would enjoy lower prices without cross-border trade.
- The second and third (much more realistic) scenarios re-establish the earlier result, that the central and western part of the SEE region aligns itself to the northwestern market

prices (40 €/MWh, in this case). When more trade is possible, the upward price pressure in AL and MK also eases.

We can therefore conclude that the only substantial difference between the three realistic cross-border capacity scenarios (minimum, average, and maximum NTC) is the market price level in the two southernmost markets: Albania and Macedonia.

Finally, Figure 11 shows the predicted auction revenues on the congested borders in each of the above three cases. (With zero trade or zero price difference between neighboring markets, there are, of course, no auction revenues.)

**Figure 37: Estimated Hourly Auction Revenues for different NTC scenarios**



This (admittedly simple) analysis suggests that there may be incentives within most of the SEE markets not to restrict trading opportunities with other markets: either to capture more congestion rents at the border (BG, RO, SR), and/or to ensure lower market prices (AL, MK, SR). Naturally, a more complete welfare analysis would be necessary to make this claim in a greater variety of settings.

## F. Potential for market power

To analyze the market power potential of generating companies, we would have to look at what happens when those companies (one-by-one) artificially restrict their output to drive up market prices and profits. Whether individual companies can have a significant effect on the market price depends on several factors (e.g. fragmentation of ownership structure, price elasticity of demand, relative supply shortage, strength of interconnection with neighboring markets, etc).

In general, we can say that market power problems are likely to become more acute when a large share of generation units belongs to a single owner, when demand is relatively inelastic (that is, it does not fall back substantially as prices rise), when demand is high to begin with (peak periods) and when interconnections easily become congested and do not allow for significant import competition.

In our modeling framework, one way to test whether quantity withholding can be profitable for a given generation company is to examine the case when this company withholds low-cost power by bidding it at a higher price. It may be that other generating units or more net imports will immediately take the place of the withheld quantity with only a negligible increase in price, in which case the company that tries to manipulate the price to its own advantage ends up losing money. It does not, therefore, have the potential to exercise market power.

On the other hand, the generation company in question may be large enough to be pivotal in the sense that some part of its production is irreplaceable and its loss steeply drives up the market price.

Given the current ownership structure of generation companies in the region (most assets are state owned); it is inevitable that these producers (jointly or unilaterally) will have significant market power in any market. If future liberalization and privatization policies yield a more dispersed ownership structure in SEE markets, the above questions can be more meaningfully

examined using our modeling approach.

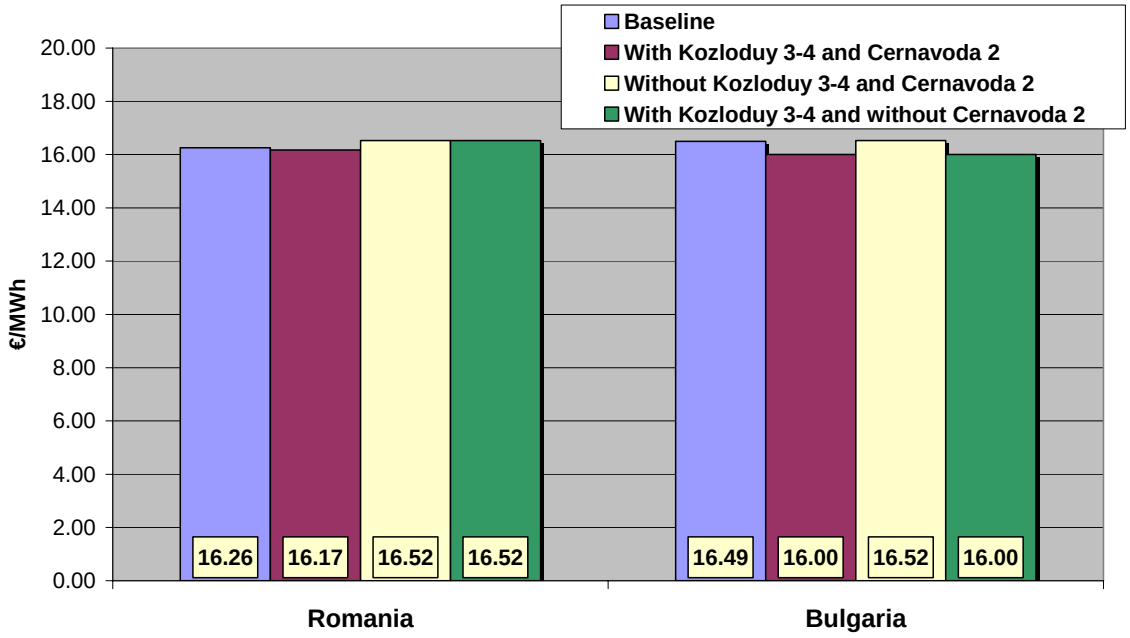
## G. Decommissioning old units

Our modeling framework also enables us to examine what happens to the short run competitive equilibrium from a regional perspective when an old generation unit is taken offline, or when a new one is introduced. We will demonstrate this feature on the following three scenarios (relative to our baseline).

- Market outcome including the recently decommissioned Kozloduy 3-4 units.
- Market outcome not including the recently introduced Cernavoda 2 unit.
- Market outcome including Kozloduy 3-4, but not including Cernavoda 2.

After evaluating all these alternative scenarios, the common result in all of them is that market prices *outside* Bulgaria and Romania do not change at all. In addition, prices even within Bulgaria and Romania are only slightly affected by the closures/openings. Surprisingly, price changes stay within 0.50 €/MWh relative to the baseline, as Figure 38 illustrates

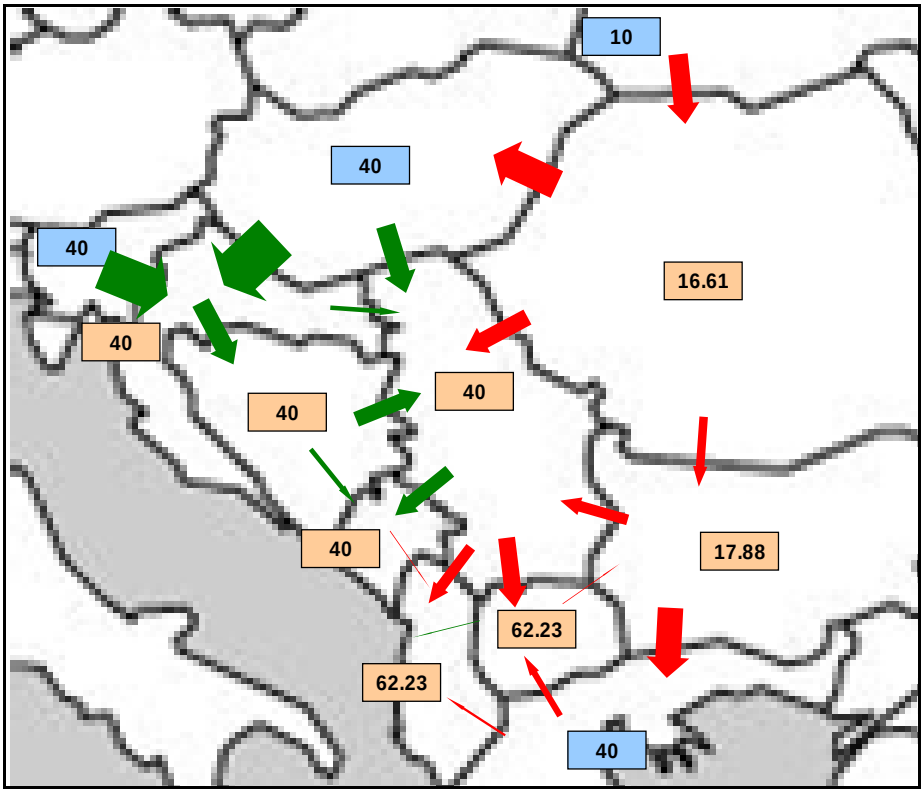
**Figure 38: Price Effects of Decommissioning**



## H. Unit derating

It may be argued that assuming 90 percent availability for thermal units is too high, even during peak demand hours. We have therefore examined an arguably more realistic case with 70 percent availability for thermal plants. The results are shown in Figure 39.

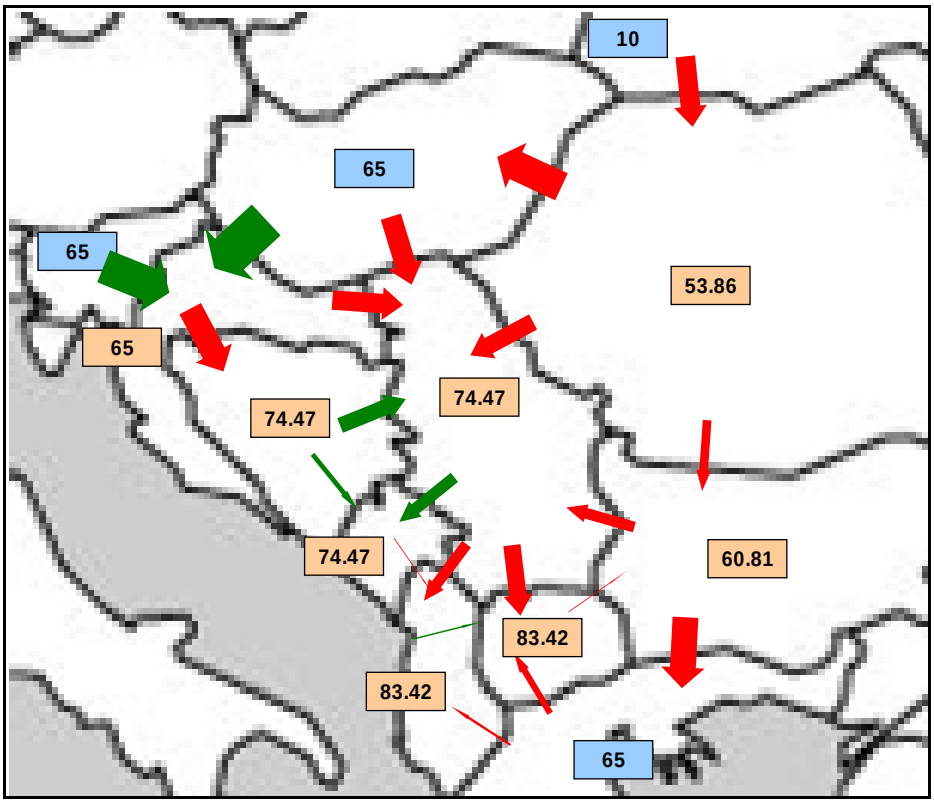
**Figure 39: Market Outcomes with 70 Percent Thermal Unit Availability**




The main conclusion from this exercise seems to be that nothing much changes in a competitive market relative to our baseline. The central and western part of SEE is still integrated with its northwestern neighbors (although it imports more heavily now), Romania and Bulgaria are still low price markets constrained outwards, and prices in Albania and Macedonia have risen by around 10 €/MWh. Congested lines remain the same as before and no new cross-border links become congested.

In order to examine an extreme unit derating case, we assumed 50 percent availability for thermal power plants throughout the SEE region, as well. We have also modified prices in three neighboring countries upwards to 65 €/MWh to reflect more current price trends. The results are displayed in Figure 14.

**Figure 40: Market Outcomes with 50 Percent Thermal Rating**




Now we do see significant price rises in all markets. Sub-regional borders still remain almost the same as before: the only difference is that Croatia is now aligned with Slovenia and Hungary, instead of its SEE neighbors. Even though the resulting market prices in the SEE region seem to be more in line with today's trends, it is important to keep in mind the circumstances that were necessary to generate this outcome (yearly peak demand, 33 percent hydro and 50 percent thermal availability) and reflect on their joint plausibility in an efficiently working electricity sector.

## I. Preliminary Conclusions

We may be able to draw some conclusions regarding the benchmark competitive market

outcomes that we can expect in a fully liberalized wholesale scenario. Some of the more robust features of a market equilibrium seem to be the following.

- Both Romania and Bulgaria are low-cost net exporters into the SEE region with relatively low internal market prices and congested borders. Reasonable changes in interconnection capacity towards the rest of the SEE region do not significantly affect prices in these two markets, as they are largely determined by domestic forces.
- Market prices in much of the central and western part of the SEE region are closely connected to the outside ("northwestern") prices prevailing in the neighboring countries for a wide variety of situations. Net exports are not unidirectional, but depend on the level of Hungarian and Slovenian prices even in the case of no congestion.
- Within the SEE region, a high-price congested sub-region consisting of Albania and Macedonia appears in certain situations, due to the insufficient internal generation capacity and relatively weak outside connections of these markets.
- Under the current ownership structure, it is very likely that most state owned generation companies have market power within their own markets which they could use to raise market prices in a liberalized scenario.

Of course, these preliminary results require further investigation to see whether they hold up under different market conditions. In addition, we may want to use the generation model to investigate questions such as:

- for what NTC values could the whole SEE region become integrated,
- the price effect of commissioning new units or decommissioning old ones,
- the effect of a more flexible usage of storage HPP capacities,
- the effect of unit derating and therefore lower available generation capacity, and
- how a change in demand conditions (level or elasticity) affects market outcomes.

As the market monitoring Pilot Plan advances, we will continue to develop our model with the goal of addressing these and other market issues that may arise.

# Appendix A

## Regional Flows September and October 2007

### Figure 41: Regional Flows at September Peak Load

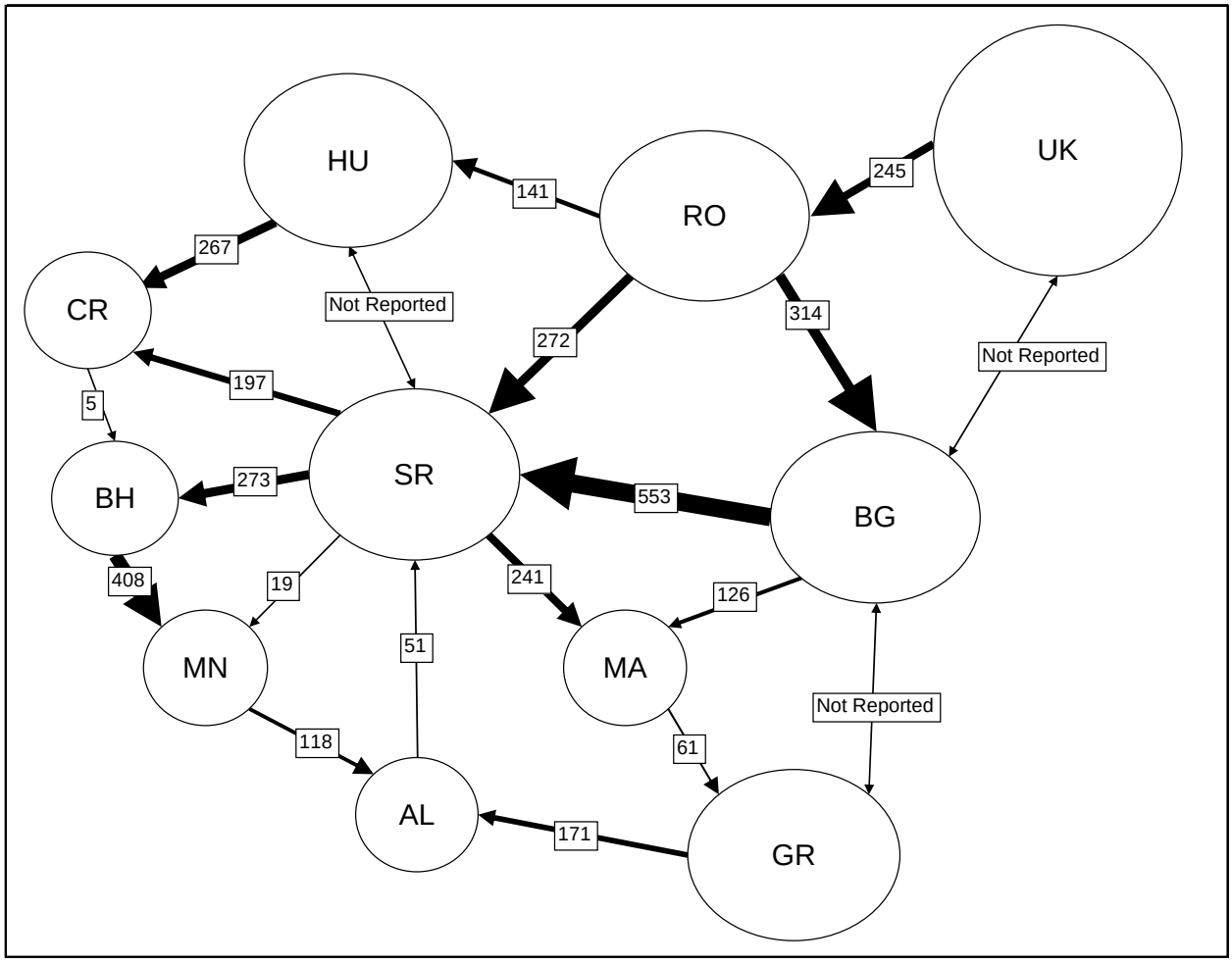
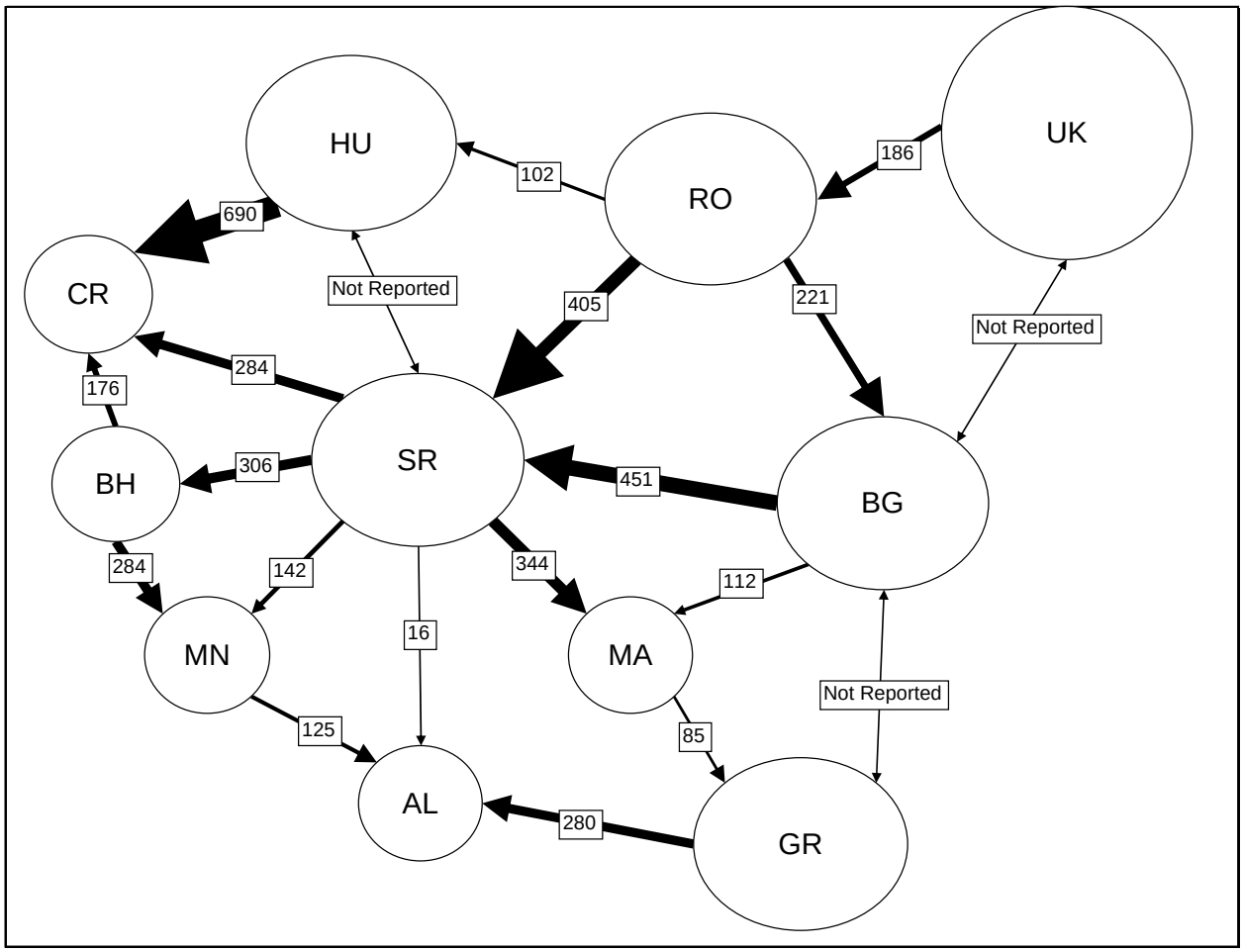



**Figure 42: Regional Flows at October Peak Load**