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Modeling Power Markets:
Uses and Abuses of Locational Market Simulation Models

Locational power market simulation models are becoming a widely-used tool for market analysis and asset valuation in regions that have implemented locational marginal pricing (LMP). However, such models are difficult to run well, and there is much debate about their ability to simulate real-world operations accurately or to provide meaningful forecasts.

The Brattle Group has extensive expertise in using locational power market simulation models in a wide variety of applications. In this issue of ENERGY, we share some of our insights into the best practices for using these models effectively.

The authors of this newsletter are Johannes P. Pfeifenberger and Samuel A. Newell. To learn more about the firm or the authors, contact them at 617.864.7900 or go to www.brattle.com.

Introduction

When it comes to power market simulation models, we frequently encounter two opposing perspectives. Some industry analysts and market participants (the fans) strongly believe in and readily apply market simulation models, while others (the skeptics) often see such models as a smoke screen for imperfect knowledge, questionable assumptions, and potentially sloppy analytics.

The skeptics have legitimate criticisms that strike partly at the fundamental limitations of simulation modeling and partly at the way simulations are typically performed. Indeed, simulation modeling can misinform, rather than illuminate, if the model is not well-calibrated and the model's assumptions, biases, and limitations are not documented.

However, a well-calibrated simulation model with transparent and reasonable assumptions can provide a structure that is uniquely well-suited for analyzing assets and operations under future or "*but-for*" market conditions. Such simulations can help quantify the effects of changes in market fundamentals, transmission constraints, market participant behavior, and ISO operations.

This issue of *ENERGY* identifies some best (and worst) practices in simulation modeling based on *The Brattle Group*'s work in a variety of consulting and litigation settings. Our discussion, which should be helpful to fans and skeptics of power market models alike, addresses the following topics:

- *Common modeling errors and shortfalls*
- *Model calibration through "backcasting"*
- *The importance of accounting for real-world disturbances, such as transmission outages*
- *Special considerations in using LMP simulation models for long-term forecasting*

Common Modeling Errors and Shortfalls

A legitimate reason to be skeptical of simulation models is that they are quite complicated and thus difficult to validate. The models can be black boxes, into which no one but the modeler can see. Even the modeler generally will not have mastered everything inside the box, and the model may not always be doing what the modeler intends. In addition, the validity of results hinges on the accuracy of input data, the model's realism (*i.e.*, its ability to simulate actual market operations), and the modeler's ability to forecast how fundamental market drivers change over time. Simulation modeling, therefore, can invite errors and shortfalls.

We have encountered five general types of modeling errors and shortfalls: data input errors, conceptual errors, poor model mechanics, failure to address biases, and failure to consider a simulation model's limited scope (see Table 1). Data input errors, for example, occur routinely because of massive data requirements, complicated data structures, and lack of tools for efficiently reviewing the data. Conceptual errors, poor model mechanics, or a failure to address a simulation model's inherent biases and limited scope can similarly result in misleading conclusions. For example, the limited scope of simulation models can lead to poor decisions if costs and benefits outside the scope are ignored or dismissed as "indirect," "intangible," or solely "qualitative" factors.

Within the scope of simulation models, the prevalence of the other errors and shortfalls listed in Table 1 underlines the importance of validating inputs and calibrating model results through backcasting. Carefully designed diagnostic reports should readily enable the review and validation of model inputs and outputs with actual market data. Such diagnostics are helpful on both an hourly and a more aggregate (*e.g.*, seasonal or annual) basis, and should address locational prices, the inputs and outputs for every generating unit, and constrained transmission elements.

Table 1 Examples of Errors and Shortfalls in Simulation Modeling

DATA INPUT ERRORS

- Duplicate or missing generating units
- Incomplete data on emissions rates
- Outdated or missing transmission constraints
- Incorrectly specified transmission constraints that sharply distort price differentials
- Formatting errors in input files that prevent the model from correctly reading the data
- Duplicate input tables where one table overrides the other with phantom data

CONCEPTUAL ERRORS

- Poorly formulated and inconsistent forecasts for fuel prices, environmental allowance prices, and the amount and types of future generation projects
- A false assumption that all "proposed" generation projects will actually get built
- Unrealistic assumptions about plant retirements
- Inclusion of generation units' fixed costs (in addition to their incremental costs) even in highly competitive markets
- Duplicative application of a price inflator to model results when data inputs are already in nominal dollars

POOR MODEL MECHANICS

- Over-commitment of intermediate units relative to peaking capacity
- Imbalances between net supply and demand plus losses
- Poor modeling of spinning reserves, hydro scheduling, and pump storage facilities

FAILURE TO ADDRESS A MODEL'S INHERENT BIASES

- Some market simulation models tend to capture only a portion (*e.g.*, one third) of actual congestion-related price differentials. The most common reasons for such poor replication of observed prices and congestion include the inadequate treatment of:
  - Dynamic deratings of transmission lines, including voltage and stability limits
  - Real-time surprises and the system's limited ability to respond immediately
  - Generation-related operating constraints and emissions or fuel limits
  - Tradeoffs between committing peaking units and intermediate units
  - Bidding behavior of market participants
  - Real-world inefficiencies introduced by the "seams" between market areas, which are inadequately reflected in the single, region-wide optimizations of most simulation models

FAILURE TO CONSIDER A MODEL'S LIMITED SCOPE

- Most simulation models do not adequately capture (if at all):
  - Markets for installed capacity and ancillary services
  - Competitive effects, such as strategic bidding in constrained-on load pockets
  - Reliability effects, such as reductions in loss-of-load probability and reliability-must-run generation costs, *e.g.*, resulting from transmission enhancements

Model Calibration through Backcasting

Effective validation of a model's simulation results with actual market data can greatly enhance the credibility of results. For example, a model's accuracy can be measured through "backcasting" locational prices and generation dispatch for a historical time period for which actual market conditions are well documented. Discrepancies between model backcasts and actual data can then be used to refine inputs, assumptions, and model algorithms.

Unfortunately, few market simulation efforts involve such backcasting. The simple reason is that most simulation models make backcasting too difficult. Most models require the user to gather detailed historical data (*e.g.*, actual loads, fuel and emission allowance prices, generation and transmission outages, and interchanges with neighboring regions) and reorganize it in a format that is compatible with the model's input data structures (*e.g.*, generating unit names or ID numbers, geographic scope of load forecasting areas, and bus numbers in the transmission system).

Backcasting with the "Dayzer" Model

A market simulation tool that greatly facilitates backcasting is the new model by Cambridge Energy Solutions (CES), called "Dayzer." Dayzer originated as a tool to inform short-term trading of energy and financial transmission rights (FTRs). This application imposed high standards that make Dayzer exceptionally suitable for both backcasting and longer-term forecasting. (*The Brattle Group* recently licensed this model to support consulting assignments.) Backcasting is an "out of the box" feature of Dayzer, enabled by input data structures that are highly compatible with actual RTO data and by automatic daily downloads that include data on loads, fuel prices, line outages, and generator outages.

With this backcasting capability in place, *Brattle* and CES have been able to fine-tune the model's representation of the physical system and develop model algorithms that closely approximate actual unit commitment, transmission losses, operating reserves, and market participant behavior. We have tested Dayzer for the PJM, MISO, NYISO, and ISO-NE market areas and found that backcasts of recent market experience – be it yesterday, last month, or last year – indeed track the actual experience quite well. Figures 1A and 1B illustrate *Brattle's* backcasting results for July 2005 market prices at the Midwest ISO's Cinergy trading hub.

Dayzer Simulations Closely Reproduce Actual LMPs

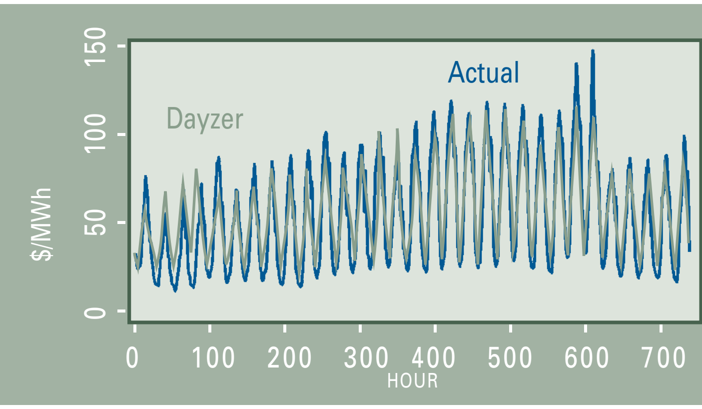

Figure 1A Hourly LMP at MISO Cinergy Hub (July 2005)

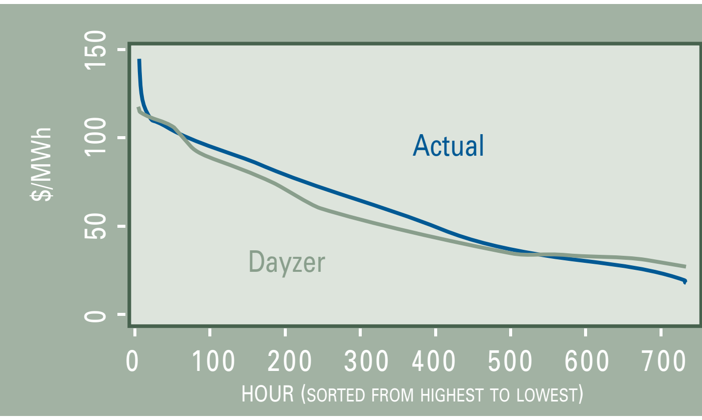

Figure 1B LMP Duration Curve at MISO Cinergy Hub (July 2005)

(continued on page 5)

CASE STUDY

ACCOUNTING FOR REAL-WORLD DISTURBANCES: ANALYSIS OF TRANSMISSION OUTAGES

Transmission outages are ignored in most simulation models, which can materially understate congestion and price differentials. To analyze the importance of transmission outages, we developed a backcast that simulates market performance with and without actual transmission outages. The backcast focused on PJM in July 2005, a peak month with a substantial (though below average) number of transmission outages. There were 481 different elements out of service for at least one day, with an average outage duration of 18 days.

Figure 2A compares the price duration curve of actual market prices for PJM's Eastern trading hub (gray line) with the Dayzer backcasts that incorporate this outage information (blue line). Figure 2B shows an example of PJM's west-to-east price differentials as measured by the difference in LMPs between PJM's Eastern trading hub and the American Electric Power (AEP) generation hub. Again, the gray line shows the price duration curve of actual LMP differentials, while the blue line shows the Dayzer backcast of LMP differentials with transmission outages.

To assess the impact of PJM's July 2005 transmission outages, we re-simulated the market assuming a fully-available transmission system (*i.e.*, without any transmission outages). These results are shown as the dark gray lines in Figures 2A and 2B. This comparison of simulated market prices with and without transmission outages yielded some rather striking results: *without* transmission outages, total PJM congestion costs were 20% lower; the value of FTRs from the AEP Gen Hub to the PJM Eastern Hub was 37% lower; the value of FTRs into Atlantic Electric, for example, was more than 50% lower; and prices in PJM East were generally understated, as were west-east price differentials.

Transmission Outages Significantly Affect LMPs and LMP Differentials

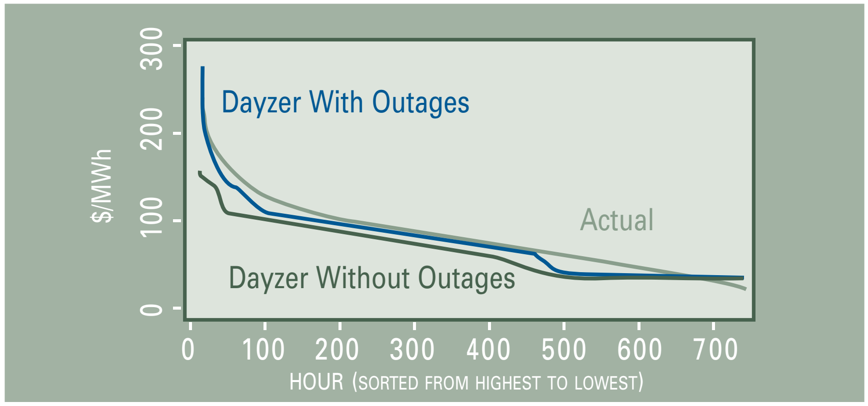

Figure 2A Hourly LMP at PJM Eastern Hub (July 2005)

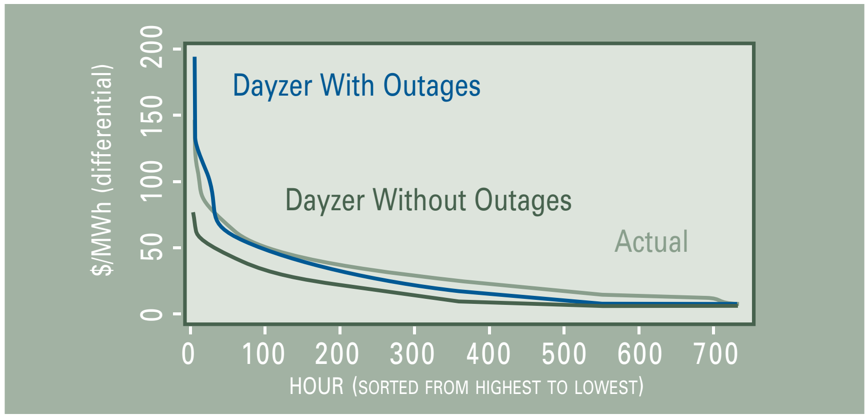

Figure 2B LMP Differential: PJM Eastern Hub Minus AEP Gen Hub (July 2005)

This analysis also showed that, among the numerous transmission outages in July 2005, congestion was most heavily affected by the outage of three individual transmission elements. A twelve day outage on PJM's Whitpain 500/230 kV transformer near Philadelphia caused severe congestion on the parallel transformer at the same station. A two-day outage of a 500/230 kV transformer at the Bedington substation in the Allegheny zone caused congestion on the 500/138 transformer at the same station. And an outage of a 230/69 kV transformer at Sands Point in the Atlantic Electric zone caused severe congestion on the Landis-Minolta 138 kV line in the same zone.

These findings suggest that transmission outages should be accounted for in market simulations. Accurate backcasts certainly need to include outages and, with Dayzer, this can be done easily. Similarly, short-term forecasts (*e.g.*, to support trading of FTRs and energy) should incorporate available data on planned transmission outages. For long-term forecasts, the significant impact of transmission outages represents a challenge: future transmission maintenance schedules are not known, and even "normal" outage patterns may be difficult to develop. If it is important to estimate the likely range of future congestion and market prices, scenario analyses of transmission outages may be warranted. Otherwise, modeling a fully intact system will understate congestion, and forecasts must be interpreted accordingly.

Insights from Backcasting Specific Events

Model calibration through backcasting also allows an assessment of the extent to which historical events have affected market prices, generation dispatch, and power flows. While specific historic events need not be reflected in forward-looking market simulations, it is often important to consider likely or potentially recurring events. For example, typical generation outages are routinely simulated and scenario analyses are sometimes used to model extreme weather conditions, unusual generation outages, or spikes in fuel costs. Transmission outages, however, are an example of real-world disturbances that are rarely considered in market simulation analyses.

The case study "*Accounting for Real-World Disturbances: Analysis of Transmission Outages*" demonstrates the importance of transmission outages through a backcast of prices with and without actually-observed transmission outages. As shown, we found that transmission outages can dramatically affect prices, congestion, and FTR values. Forecasts that entirely ignore transmission outages, as most do, must therefore be expected to understate congestion by potentially very substantial amounts.

The importance of considering transmission outages is also underlined by the current efforts of both PJM and MISO to allow market participants to reduce congestion costs by paying transmission owners to accelerate their transmission maintenance schedules.

Special Considerations for Long-Term Forecasting

After a model has been calibrated to capture present or recent market conditions, simulating the future becomes an exercise in varying the model inputs from their present values. The modeler must project changes in load, fuel prices, emission allowance prices, available generating capacity, generation technology, transmission enhancements, and market structure. Forecasting the necessary input data is most easily done for short-to-medium-term time frames (a few days to a few years) when planned enhancements to the physical infrastructure and forward prices for fuel and emissions are observable. The great precision of nodal simulation models can provide highly granular insight into how prices might evolve over this time frame.

Long-Term Forecasts are Driven by Assumptions

The application of simulation models for long-term forecasting is more challenging. The further the simulation extends into the future, the less data is available on how the system and market fundamentals will change. Consequently, the inputs needed for long-term simulations are driven increasingly by the modeler's projections, which require considerable expertise outside of the scope of the simulation model itself. While market simulation models provide a platform for analyzing the effects of the modeler's projected inputs, they do not provide the assumptions, intelligence, or theory to guide the development of these inputs. In fact, the time-consuming process of mechanically running a model and the seductive apparent precision of the simulation outputs can prevent modelers from paying sufficient attention to the development of meaningful assumptions and the projection of required input data.

One of the most critical inputs for long-term simulations (or any fundamentals-based analysis of future markets) is the projected amount, type, and location of new generating capacity – which is built over time in response to load growth, plant retirements, and other changes in market conditions. Assumptions must be made in particular about the time period after the completion of already-planned generating stations (*e.g.*, years 5 through 20 of a 20-year forecast). To avoid speculation, however, such assumptions need to be informed by available data on likely market equilibriums that consider the cost of entry, consistent fuel and emission allowance prices, and environmental regulation.

Key Concept: Long-Run Market Equilibrium

To bridge the gap between medium-term forecasts and a long-term market equilibrium, *The Brattle Group* typically constructs a base scenario in which the market converges from known current and near-term conditions toward a long-term *equilibrium*: just enough capacity gets built to meet required planning reserve margins, and energy plus capacity prices are just enough to induce the last unit of new generation to enter the market. This approach does not assume that long-term market conditions will necessarily reflect this equilibrium. Rather, the constructed equilibrium simply reflects rational expectations for an average outcome in which power plant developers neither make money-losing investments nor miss opportunities to earn their cost of capital. With such equilibrium projections of market conditions as a baseline, the possibility of boom-bust cycles of excess capacity and generation shortages can then be addressed through scenario analysis.

The key assumption in applying this long-term equilibrium approach is the long-run marginal cost (LRMC) of available generating technologies. However, despite the fact that LRMC can be the most significant factor in determining the value of generation assets and long-term power contracts, we tend to encounter analyses that address this issue with surprisingly little thought and rigor.

Analysis of LRMC

LRMC depends on equipment and installation costs, fixed O&M costs, and various financial assumptions affecting the annual “revenue requirements” of new entrants. The financial assumptions must be consistent with the risk of the project, the market cost of capital, taxes, depreciation, and expected market and technological evolution. *The Brattle Group* uses a detailed financial model to ensure that projected LRMC accurately captures and consistently considers these factors. This model informs the equilibrium mix of capacity, *e.g.*, natural gas-fired combustion turbines and combined cycle units, new coal generation, and renewables, that can be expected to be built under various market conditions. Given the LRMC of each technology, the mix of new capacity can be analyzed with the simulation model to identify the most economic entrants, based on simulated energy margins. Once the optimum mix is identified, the simulation model can be used to estimate equilibrium energy prices and the expected energy margins of generating units.

This approach also allows for the estimation of capacity prices, which are the other main source of a generator’s revenues, and which are generally outside the scope of the simulation model. At equilibrium, the capacity price is set by the amount that efficient entrants need in order to cover their LRMC net of energy margins.

LRMC is Part of a Larger Toolbox

A significant number of additional inputs are needed for long-term forecasting, the development of which are similarly outside the scope of power market simulation models. However, complementary tools are available to develop these inputs systematically, such that they are consistent with available data, market fundamentals, and economic theory.

For example, a tool to address these issues in a highly uncertain environment from a supply planning perspective is *The Brattle Group*’s Capacity Alternative Levelized Cost Screen (CALCS). This screening model compares all-in generation costs for competing technologies under a range of fuel and emission allowance prices and other variables, to define the conditions favoring each technology. Similarly, our Capacity Alternative Multi-year Evaluation and Risk Assessment (CAMERA) model informs supply planning decisions by evaluating the risks of different resource options under several coherent scenarios concerning fuel markets, environmental regulation, and technological change. It determines the value of resources over different time periods, quantifies the “option value” of flexible investments, and identifies best overall alternatives under various decision criteria. These tools can also be used to construct a consistent set of the inputs required for long-term simulations of locational power markets.

For risk assessment or the analysis of alternative bidding behaviors, locational simulation models may need to be combined with streamlined models that more readily allow for iterations and Monte Carlo simulations. We have developed the *Brattle* Annual Model (BAM), a fast-running production cost model, to support such analyses.

CONCLUSION

Locational power market simulation models are often relied upon for analyzing assets and electricity markets. However, many skeptics view them as black boxes, the workings of which are difficult to see or to validate. Contributing to this perception is the often surprising prevalence of modeling errors and shortfalls, including the failure of some modelers to validate their data inputs and modeling algorithms, or to address the biases and limitations of their model.

"Backcasting" is a highly effective way to calibrate and validate simulation models. Backcasts also allow the explicit incorporation of real-world disturbances that are easily glossed over in simulation modeling. For example, transmission outages have proven to be a major determinant of observed congestion and locational prices. This suggests that forecasts which do not consider transmission outages may significantly understate the level of transmission congestion.

Well-calibrated backcasts can form a solid starting point for simulating future periods. Given an accurate representation of today's system, simulating the future becomes an exercise in varying the model inputs from their current values.

However, there are special challenges in using LMP simulation models for long-term forecasts, which are driven largely by the modeler's projections and assumptions about critical input parameters. The projection of inputs is often insufficiently scrutinized because the simulation models themselves do not generally guide the development of assumptions, and considerable expertise outside the scope of the model is needed.

For example, one of the most critical inputs in a simulation model is the projected amount, type, and location of new generating capacity. This depends on the long-run marginal cost of entry and on other market fundamentals affecting likely market equilibriums. To fill these gaps, supplementary tools can help develop projections and assumptions that are consistent with available data and economic theory.

Simulations of future markets cannot be expected to predict future market conditions perfectly, as unexpected and unknowable system disturbances and shifts in market fundamentals can greatly influence actual outcomes. However, simulations that are calibrated to represent the current system accurately, and that incorporate carefully developed projections about how fundamental drivers will change over time, can better inform the questions that require us to look into the future. When applied in concert with complementary tools and necessary expertise, market simulations are invaluable for analyzing assets and operations under future or "but-for" market conditions.

THE BRATTLE GROUP'S EXPERIENCE IN POWER MARKET SIMULATION MODELING

The Brattle Group and its team of experts have extensive market modeling expertise based on years of experience with several models in a wide variety of applications involving business decisions, energy policy matters, and commercial disputes. Specific assignments have included:

- Valuation of generation and transmission assets
- Determination of contract damages in expert testimony and in support of settlement discussions and contract renegotiations
- Transmission planning efforts and cost-benefit analyses of transmission upgrades
- Evaluation of RTO choices and RTO seams
- Assessment of industry restructuring and market design features on prices, fuel use, and inter-regional power flows
- Evaluation and calibration of clients' in-house simulation models

Members of *The Brattle Group* have worked with all of the major market simulation models commonly used in the industry, including GE-MAPS, PROMOD IV, Henwood's integration of MarketSym and PowerWorld, the Inter-Regional Electricity Market Model (IREMM), and Cambridge Energy Solutions' Day Ahead Analyzer (Dayzer) and Transmission Analyzer (Tranzer). Our experience with these platforms has proven to be highly effective not only in supporting our own analyses, but also in the discovery phase of litigation assignments and the cross examination and rebuttal of opposing witnesses.

The Brattle Group frequently combines its simulations of locational power markets with capacity expansion models, long-run marginal cost models, stochastic models of power and fuel prices based on spot and forward market data, portfolio and risk management models, as well as cost-benefit and financial valuation models.

In addition to this modeling experience, *The Brattle Group* brings to its assignments exceptional expertise in related subject areas, including industry structure and regulatory policy, fuel markets and environmental compliance matters, analysis of markets for mergers and acquisitions, support of market-based rates applications, financial evaluation of procurement and risk management decisions, economic damages, and litigation support.

NEXT ISSUE: WHEN SPARKS FLY: Economic Issues in Complex Energy Contract Litigation

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The Brattle Group

44 Brattle Street
Cambridge, MA 02138-3736
Voice 617.864.7900
Facsimile 617.864.1576

www.brattle.com office@brattle.com

353 Sacramento Street
San Francisco, CA 94111-3657
Voice 415.217.1000
Facsimile 415.217.1099

1133 Twentieth Street NW
Washington, DC 20036-3408
Voice 202.955.5050
Facsimile 202.955.5059

Rond Point Schuman 6, Box 5
1040 Brussels, Belgium
Voice +32.2.234.77.50
Facsimile +32.2.234.77.40

1st Floor 198 High Holborn
London WC1V 7BD
Voice +44.20.7406.1700
Facsimile +44.20.7406.1701