



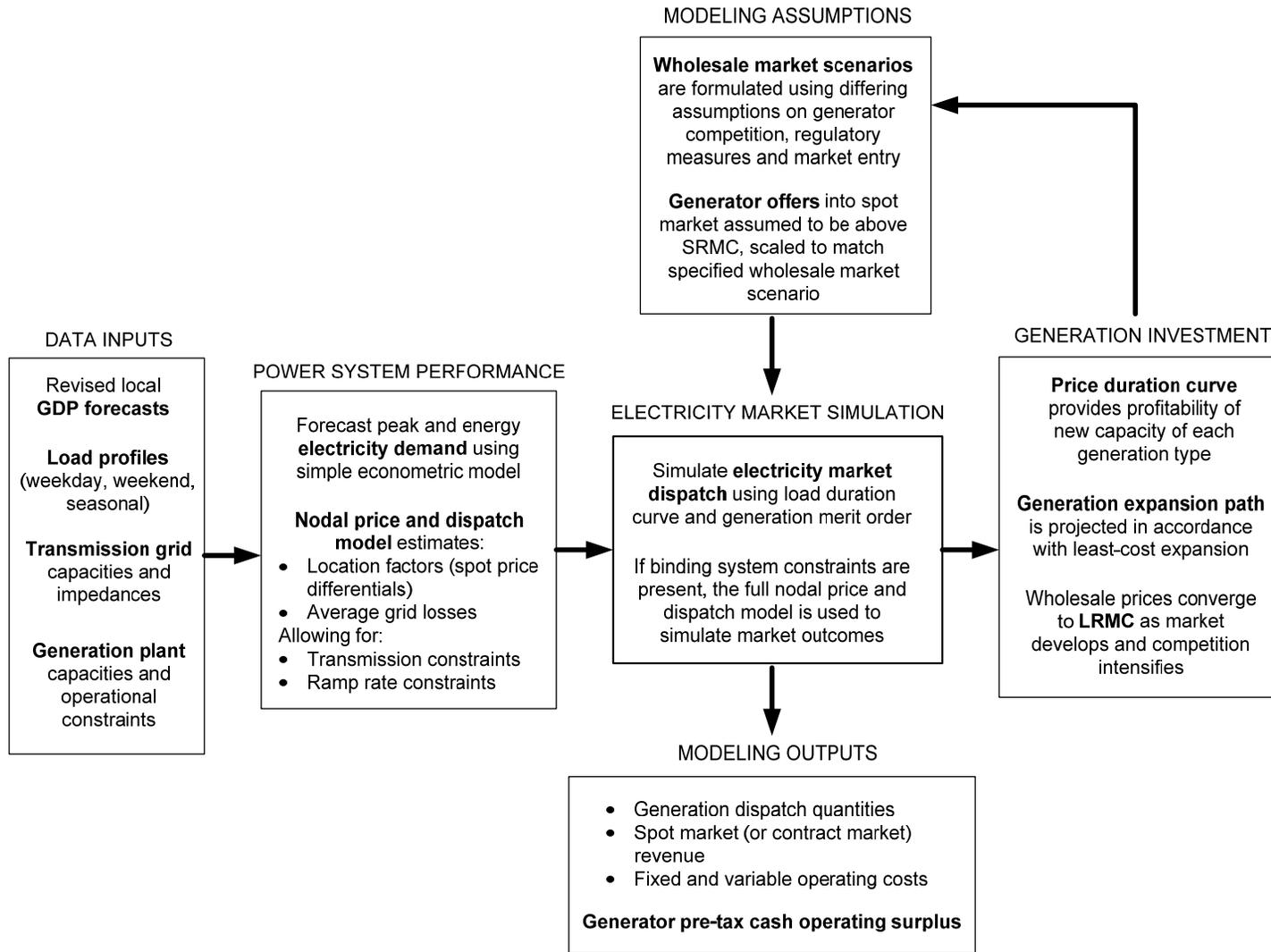
Electricity Market Modeling for the Valuation of Generation Plants

Figure 1 provides an overview of Castalia's approach to modeling an electricity market for the purposes of generation plant valuations. We have formulated this approach through our experience valuing generation plants and from our understanding of the key variables affecting market outcomes. We divide the key features of our electricity market model into six groups:

- Modeling assumptions
- Data inputs
- Power system performance
- Electricity market simulation
- Generation investment and
- Modeling outputs.

This note also provides a discussion of the important elements considered in our modeling.

Figure 1: The Castalia Modeling Suite for Valuing Generation Plants



Wholesale market scenarios depend on assumptions outside the modeling regarding: the intensity of competition between generation owners (affected by the degree of ownership break-up achieved by the privatization program), regulation of earnings through vesting contracts and possible over-capacity through premature construction of new generation. These assumptions are encapsulated in **wholesale market scenarios** for average wholesale spot prices, which will be consistent with achievable baseload wholesale contract earnings.

GDP forecasts are required to help forecast electricity demand growth. Domestic government forecasts of economic growth are often inflated so we counterbalance local views with forecasts from international sources such as the IMF World Economic Outlook Database.

Load profiles are obviously crucial inputs to modeling dispatch. We extract representative weekday and weekend profiles from market data and allow for seasonal variations as well.

Transmission grid parameters are required for the nodal pricing and dispatch model. Most power markets provide participants with comprehensive information about the transmission network and this is generally made available to bidders in privatization processes.

Electricity demand forecasts drive the dispatch and new capacity modeling. Using past demand growth trends and a simple econometric model of the relationship between economic growth and electricity demand growth, we develop scenarios for peak and energy demand growth, essentially forecasting the development of the full load profiles.

Generation plant capacities complete the inputs required for modeling dispatch. Plant capacities are generally registered with, and published by, the system operator and more detailed information on the plants of most interest is generally provided in information memoranda. Memoranda usually include outage histories, heat rates and operational constraints like limits on ramping. We generally have to make our own estimates of plant short run marginal costs (SRMCs), principally combining achievable heat rates and forecasts of regional fuel prices.

The **nodal price and dispatch model** combines generation and transmission capacities with load forecasts and estimates plant utilization by mimicking the optimization software used in the operation of the actual commercial spot market. As explained below, we assume that price “offers” by generators of plant into the spot market are in the same order as the plants’ short-run marginal costs thus yielding efficient dispatch. The model captures the effect of any constraints in the transmission grid or in plant operation and calculates nodal prices at each point in the grid—expressed in “location factors” relative to spot prices at some central grid point.

Electricity market dispatch is simulated over the load profile for each future year. In most settings transmission constraints are unlikely to persist and plant operational constraints are minor. In these cases we use location factors from the nodal price model but can simplify the dispatch simulation substantially by treating half hourly loads independently. The approach is illustrated in the figure below and explained in the following paragraphs.

Different types of plant have different SRMCs. In the wholesale market, plants compete with each other to supply power. Generation owners are free to bid whatever price they like, but clearly will not usually offer to supply power at less than SRMC.

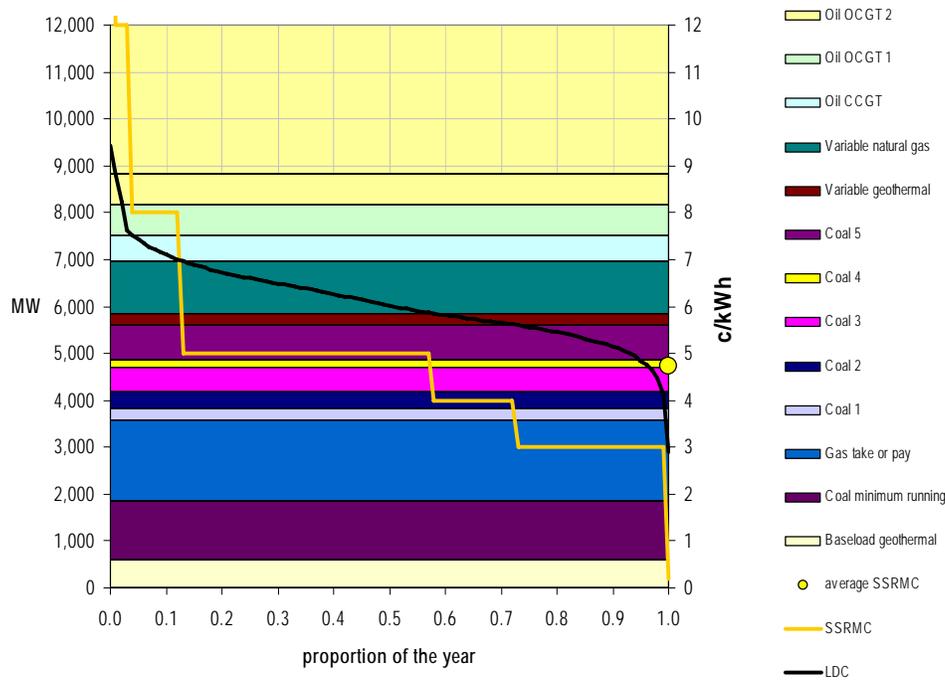
In circumstances where plants are competing with each other, competition can drive prices down *toward* the SRMC for the marginal plant. (This is because each of the competing plants

wants to be dispatched, and so will try to offer a lower price than the other plants, subject to still covering its variable costs).

For these reasons it is useful to analyze the supply of generation by considering the SRMCs of the available plants. We do this by developing a ‘generator stack’. A generator stack simply adds up the capacity of the available generators by type, starting from those with the lowest SRMC and moving up to those with the highest SRMC. The idea is that, in general, demand will be met first by plant with the lowest SRMC. Then in periods with higher demands, progressively more expensive plant will be dispatched.

The figure depicts the generator stack for a typical modest sized power system. The horizontal slices represent the MW capacities of the plants offered to the market. Plants with very low SRMCs or take or pay fuel contracts are low in the stack, coal plants are likely to be in the middle and oil-fired plants are at the top.

Load Duration Curve/Capacity Stack Analysis



The figure also shows the Load Duration Curve (LDC), the downward sloping solid black curve. This shows how high demand is for each period of the year, with the separate half hourly loads depicted in size order. Efficient dispatch requires that just those plants below the LDC in the stack will be dispatched in each period of the year. The load duration curve is “augmented”—especially at peak times—time allow for the effect of outages on the dispatch of peaking plants.

Hence the figure depicts directly the efficient utilization of each plant, 100 percent for the lower-order plants and minimum running levels, moderate plant factors for coal and gas plants with intermediate fuel costs, and only light utilization of the peaking plants that have high fuel costs.

Finally, the figure also shows, for each period of the year, the SRMC of the plant that is on the margin (that is, the highest plant in the stack that is dispatched)—assuming efficient dispatch. The SRMC “price duration curve” is shown in the figure as the yellow line stepping downwards to the right. The curve records the proportions of the year during which the SRMC is above the level indicated on the right-hand axis. A yellow spot on this axis shows the annual average of the SRMCs.

Actual **generator offers** will generally be above SRMCs. Usually the number of competing generator firms is small and the firms “game” the market to keep spot prices up so as to be able to persuade retailers to buy short-to-medium-term contracts at higher prices. In a “Cournot” approach to modeling the outcome of this gaming, the rising sequence of SRMC offers is simply scaled up. The offers are thus in the same order as SRMCs and dispatch is efficient—the same as it would be with SRMC offers. We choose the scaling parameter so that the average of spot prices matches the relevant **wholesale market scenario** described earlier.

The spot market **price duration curve** indicates the potential earnings of additional capacity. The area under the curve and above a price level on the right-hand axis corresponding to the offer price of the prospective new plant is the hourly profit per kW of new capacity.

We assume that the **generation expansion path** is driven by market fundamentals rather than by spot market power. Accordingly, we forecast expansion of each type of capacity on the basis of the yellow SRMC price duration curve in the figure, evolving as demand grows. In the long run we assume that supply and demand come into balance and average wholesale prices converge to **LRMCs**.