Energy Policy #vol# (xxxx) xxxx–xxxx

Contents lists available at ScienceDirect

Energy Policy

journal homepage: www.elsevier.com/locate/enpol

Tales of two islands – Lessons for EU energy policy from electricity market reforms in Britain and Ireland☆

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ARTICLE INFO

Classification codes:
D47
H23
L94
Q48
Q54*Keywords:*
Reliability
Sustainability and affordability
Capacity auctions
Contract design
Renewables

ABSTRACT

Britain considers the energy-only EU Target Electricity Model (TEM) wanting in delivering the trilemma of reliability, sustainability and affordability and argues that a capacity auction with long-term contracts for new entrants is the least-cost solution compared to relying on expectations of future prices to deliver adequate generation and demand side response. The Energy Union argues against feed-in tariffs (FiTs) for renewables, pressing for premium FiTs (pFiTs), just as GB has abandoned PFiTs in favour of FiTs. This paper draws on the GB experience of Electricity Market Reform before and after the 2015 change of government, to highlight promising resolutions of the energy trilemma, and the problems that have arisen between the diagnosis of the problem and the delivery of solutions. It sets out the theory and practice of delivering capacity, energy and quality of supply, gives a brief history of GB electricity from the CEGB to its current unbundled, liberalized and privatized structure. That sheds light on the trilemma problem and discusses possible solutions. The island of Ireland Single Electricity Market reforms illustrate the problem and possible answer of how best to deliver quality of service with high intermittency.

1. Introduction

Britain has taken a careful look at the energy-only market model that underpins the EU Target Electricity Model and has found it wanting in delivering the objectives of reliability, sustainability and affordability.[1] On *reliability* or security of supply, Britain argues that a capacity auction with long-term (15-year) contracts for new entrants is the least-cost solution compared to relying on expectations of future market prices to deliver adequate investment in a timely fashion. Capacity markets raise important issues for cross-border trade and this paper argues that the approach of the proposed Integrated Single Electricity Market (I-SEM) of the island of Ireland has merit in avoiding the need for pan-EU harmonization of capacity mechanisms. The I-SEM has additional lessons for reducing the missing money problem argued to justify capacity markets, by creating new flexibility services to partially address the missing market problem.

On *sustainability*, or decarbonization, the *Energy Union* (EC, 2015) argues against supporting renewables with classic Feed-in Tariffs (FiTs), pressing instead for premium FiTs (pFiTs), just as GB has abandoned PFiTs for something closer to FiTs.[2] While the EU is beginning to accept that its Emissions Trading System is inadequate for guiding low-carbon electricity investment, GB has enacted a carbon price floor intended to underwrite long-term contracts for low-carbon investment.

On *affordability*, this paper provides evidence that auctions, rather than bureaucratically set prices, dramatically lower the cost of long-term contracts for renewables and capacity.

This paper draws on the GB experience of Electricity Market Reform before and after the 2015 change of Government, to highlight promising resolutions of the energy trilemma in the electricity supply industry (ESI), and the problems that have arisen between the diagnosis of the problem and the delivery of solutions. Section 2 sets out the theory and practice of delivering capacity, energy and quality of supply to the wholesale market and final consumers, followed by a brief

☆ Paper building on the presentation to “A New Model for Electricity Markets? Towards a Sustainable Division of Labour between Regulation and Market Coordination” held in Paris–Dauphine on 8–9 July 2015. The author is a member of the Panel of Technical Experts advising DECC on capacity auctions and a member of the SEM Committee of the island of Ireland but is writing solely in his academic capacity, using only published material, and the views expressed here do not reflect the views of either organisation. I am indebted to Anette Boom, Thomas Greve and anonymous referees for helpful comments, but I am responsible for remaining errors.

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[1] The Target Electricity Model was influenced by Nordic markets, where large volumes of storage hydro, ample capacity and interconnection could make the energy-only market model appropriate.

[2] Acronyms listed at start.

http://dx.doi.org/10.1016/j.enpol.2016.10.015
Received 8 June 2016; Received in revised form 10 October 2016; Accepted 15 October 2016
Available online xxxx
0301-4215/

Nomenclature

CCGT	Combined cycle gas turbine
CfD	Contract for difference. This obliges the issuer (the generator) to pay the excess of the market price over the strike price per MW of contract or to receive the shortfall if the market price is below the strike price
CoNE	Cost of new entry
CP	Capacity payment
DECC	Department of energy and climate change
EMR	Electricity market reform
ESI	Electricity supply industry
FiT	Feed-in tariff: a fixed price per MWh of metered output
G	Generation
I-SEM	Integrated SEM
L	Load
LoLP	Loss of load probability
MSQ	Market scheduled quantity
MW	Megawatt
MVA	Megavolt amps, takes into account both the resistive and reactive load.
NETA	New electricity trading arrangements introduced 2001
pFiT	Premium FiT
QoS	Quality of supply
RES	Renewable electricity supply
RO	Renewable obligation
ROC	RO certificate
SEM	Single electricity market of the island of Ireland
SMP	System marginal price
SNSP	System non-synchronous penetration – e.g. wind
SO	System operator
T-4, T-1	Auctions held 4 or 1 year before delivery
TEC	Transmission entry capacity, replaced declared net capacity, DNC
TNUoS	Transmission network use of system
TSO	Transmission system operator
VoLL	Value of lost load
WACC	Weighted average cost of capital
XBID	Cross-border intraday market project enables continuous cross-zonal trading

history of the evolution of the GB ESI from a vertically integrated centrally planned state-owned company to its current unbundled, liberalized and privatized structure and the problems this presented in resolving the trilemma of reliability, sustainability and affordability. Section 4 describes the diagnosis and proposed solution to that problem, which were not peculiar to GB. Section 5 therefore studies the Single Electricity Market (SEM) of the island of Ireland, which faces higher intermittency with a lumpier and more isolated system than almost any other country. It raises the question how best to deliver reliability and quality of service with high intermittency. The British Isles (the UK *and* Ireland) therefore have important lessons for the EU *Energy Union*, drawn out in Section 6.

2. Pricing electricity: from central planning to liberalized markets

Electricity appears the archetypical homogenous commodity that underlies micro-economics – all electrons look the same – but that is deceptive. Capacity (MW) limits peak demand, energy (MWh) and power (MVA) vary over time and space, and quality of service includes stability of frequency and voltage, while the phase angle affects the ability to extract power from energy. Quality of service requires a variety of ancillary services supplied by generation or demand (reserves, reactive power, frequency response, black start capability, etc.) and in turn requires grid codes/standards on those connected (fault ride-through, ability to remain connected up to a specified rate of change of frequency, etc.). Generation plant may have fixed start-up costs, limits on the rate at which it can ramp up to full power, varying efficiencies at different plant loads, minimum stable generation output, minimum down-time between operations, etc. The transmission system has limited capacity to move power between nodes and the system has to be able to withstand the loss of at least one of the largest components (the largest single infeed - generator or interconnector - or the largest transmission link: the N-1 constraint).

Determining the least-cost dispatch to meet time and space varying demands is difficult as it is a non-convex problem with strong intertemporal dependencies. In centrally dispatched systems, the System Operator (SO) typically solves this with a Mixed Integer Program optimizing over a future period (a week for thermal systems, longer for hydro systems), to determine the optimal security-constrained dispatch (including necessary reserves and other ancillary services). The dual of this optimal quantity program is the scarcity value of electricity at each node (the nodal price or Locational Marginal Price, LMP). LMP theory, set out by Schweppe et al. (1988), has been implemented in large areas of the U.S. as the Standard Market Design. In the pioneering region of PJM,[3] nodal prices are recomputed every five minutes.

In a vertically integrated system in which transmission and generation are in a single company (the standard model for most countries until the 1980s) investment decisions in transmission and generation could be coordinated to deliver least-cost delivery of power to the grid supply points at which the regional distribution networks connect. These distribution networks were usually under different management (although often under the same state ownership) and were often charged on their specified peak power, and then a variable energy charge, with higher prices for exceeding the specified peak. The distribution network operators then translated this Bulk Supply Tariff into charges for consumers (differentiated by voltage level and whether half-hourly metered and with what maximum demand allowed or taken).

Efficient investment planning requires the right type, size, location and delivery date of generation units. Previously, these were typically large thermal stations constrained by access to fuel, cooling water, and grid connection. Transmission planning had time horizons of 60+ years, and given the constraints on securing suitable way-leaves (overcoming local opposition), had long lead times and limited choices, while locating generation assets was in principle easier. Nevertheless, tight coordination of the location and timing of generation and transmission offered the prospects of considerable saving – important when nuclear power stations need to come off-line to refuel periodically and the grid needs adequate capacity to wheel replacement power in from other sources.

State-ownership provided access to low-priced capital but limited incentives for efficient investment (operation was usually better, run by engineers and monitored by the SO), particularly as the unions had enormous threat power and extracted high rents. Privatization without liberalization risked monopoly without improved efficiency, liberalization required unbundling to prevent entry deterrence, and unbundling required markets to replace central decision making. Creating suitable markets and ensuring efficient investment and dispatch is difficult, given non-convexities in operation and synergies in investment. Competitive markets can only guarantee efficient outcomes if there are no market failures, and sufficiently dense risk and futures markets for all products supplied and demanded (capacity, energy and

[3] The Pennsylvania, New Jersey and Maryland interconnection, now much wider.