EIRGRID
East West Interconnector

Integrated Single Electricity Market (I-SEM)

Financial Transmission Rights Consultation Paper
SEM-15-061

A Submission by EirGrid Interconnector Limited

19 October 2015

Contents

INTRODUCTION

EirGrid Interconnector Limited (EIL) welcomes the publication of the Financial Transmission Rights (FTR) Consultation Paper and the opportunity to respond to these proposals.

The East West Interconnector is a high-voltage direct current (HVDC) interconnector which links the electricity transmission grids of Ireland and Great Britain. The East West Interconnector is a fully regulated interconnector which is owned by EirGrid Interconnector Limited (EIL), a wholly owned subsidiary of EirGrid Plc and is operated in accordance with the Interconnector Operator licences issued by CER and Ofgem. SONI acts as Interconnector Administrator[1] for both of the interconnectors that connect the island of Ireland and GB.

Our approach to operating the East West Interconnector is underpinned by the following points:

1. We operate the East West Interconnector to maximise benefit to consumers.
2. Revenue from the East West Interconnector does not go to EirGrid's bottom line. EirGrid's profits are not affected by revenue from the East West Interconnector.
3. The operation of the East West Interconnector is fully regulated; it is fully compliant with European and national regulatory requirements in relation to open access.

EIL has procured the services of industry experts and market modelling specialists Baringa Partners to assist in the assessment of the implications of the questions put forward in this consultation. This response refers to the Baringa report which has been provided together with the response.

[1] The "Interconnector Administrator" is a defined role under the Single Electricity Market Trading and Settlement Code. It is part of the SONI license to provide this and the "Interconnector Error Administrator" services as such expressions are defined in the GB Balancing and Settlement Code for the Moyle interconnector. SONI also provides these services to the EirGrid East West Interconnector.

GENERAL OBSERVATIONS

EIL agrees with the objectives set out in the consultation document and acknowledges that any of the options under consideration will need to be compliant with the Forward Capacity Allocation Guideline (FCA GL), once it is finalised and enters into force, which is likely to be Q2 2016. TSOs will then be required to develop a proposal for the type of long term transmission rights by Q4 2016.

The latest draft of the FCA GL (30/09/15) requires TSOs to develop a proposal for the type of long-term transmission rights to be issued, including a schedule for implementation. TSOs are required to publicly consult on this proposal in advance of approval by the relevant National Regulatory Authorities (NRAs). The SEM Committee decision is to adopt Financial Transmission Rights (FTR) and the current consultation on the type of FTR product to be offered in I-SEM will be completed in advance of the required consultation obligation as set out in the draft FCA GL.

EIL will work with its colleagues in ENTSO-E to develop the final Allocation Rules for Forward Capacity Allocation (HAR) during 2016 (see Table 1: Implementation Timelines of the Single Allocation Platform) which will address any modifications in the FCA GL once it enters into force. These modifications have not been included in the recently consulted HAR which forms part of the approved East West Interconnector Access Rules.

The HAR, Annex 12 – Border-Specific Annex: GB-SEM and the EWIC Access Rules and the HAR annex describing the products per border will form part of the annual access rules consultation process in 2016. It is anticipated that the SEM Committee will have made a decision on the type of long term transmission rights in December 2015. This decision will feed into the proposed product for the GB-SEM border which will be modified to be consistent with that decision.

The consultation paper does not mention any approval required from Ofgem as part of this process. The Forwards and Liquidity Discussion Paper (SEM-15-010) noted that the I-SEM HLD proposal to use FTRs was subject to agreement with Ofgem. We think it would be beneficial to note any Ofgem approval or further required steps as part of the Decision Paper to give clarity to the market on the future arrangements.

RESPONSES TO THE QUESTIONS POSED IN THE CONSULTATION PAPER

Responses to the questions from the consultation are provided below.

1) FTR OPTIONS OR FTR OBLIGATIONS

1. Which offers the greater benefit to the I-SEM/GB market: FTR Options or FTR Obligations?

EIL's view is that FTR Options will offer greater benefit to the I-SEM/GB market in the time period between I-SEM go-live and the full establishment of the Single Allocation Platform (SAP) which will comply with the EU Harmonised Allocation Rules (HAR) as required by the draft FCA GL. After this timeframe, the decision on FTR product type should be based on the detailed assessment of economic benefits and facilitation of greater liquidity.

A decision to implement FTR Obligations now would be detrimental to the market and would represent a significant implementation challenge. The HAR for FTR Obligations have not been drafted at this point. In the absence of HAR for FTR Obligations, it will not be possible to implement a solution which embraces European integration at this stage; rather we would have to implement a local solution with I-SEM rules for FTR Obligations. If a local solution is developed this would effectively marginalise the I-SEM from the full opportunity of joining a platform such as JAO would offer, which has over 150 actively trading market participants.

Implementation and operations costs will be far higher for FTR Obligations given that the end-to-end solution would need to be developed solely for local needs. The administration of long-term arrangements would also remain local, including all the following activities; customer registrations, credit cover management, auction management, secondary market, settlement, invoicing, clearing house interfacing, etc.

It would be preferable to wait until the FTR Obligations solution is available on the SAP.

EIL would not recommend the development of I-SEM specific rules for FTR Obligations as this would also result in the GB-SEM border being non-compliant with the currently approved HAR. These rules were approved by the CER[2] and Ofgem[3] on 15th October 2015.

As compliance with the HAR is required, the entire set of rules associated with FTR Obligations would need to be incorporated into the GB-SEM border specific annex and approved during 2016 by both Ofgem and CER. Local systems for FTR Obligations would also need to be developed in advance of this approval to meet I-SEM long-term capacity auction timelines. These requirements are not feasible in practice.

Assessment of the greater benefit to the I-SEM/GB market includes consideration of the:

(a) availability of EU Harmonised Allocation Rules for each product;
(b) availability of suitable Allocation Platforms for each product;
(c) complexity involved in establishing the business readiness for each product;
(d) cost of collateral associated with each product;
(e) accessibility of the product to customers;
(f) familiarity with each product in the context of existing European electricity traders;
(g) resulting liquidity that the product offers and associated liquidity in the CfD markets either side of the interconnectors;
(h) likelihood of substantive value adding netting for FTR Obligations; and
(i) stability of the market and predictability of market prices.

Each of these considerations (a) to (i) are explained further below.

Economic advice provided by industry experts Baringa considers a number of the above points and on balance judges FTR Options to be favourable for the reasons of risk-aversion, likely over-discounting, and lack of familiarity with FTR Obligations. The details of the full Baringa analysis are available in the Appendix to this response.

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[2] CER approval of EWIC Access Rules and Charging Methodology Statement 2015
http://www.allislandproject.org/GetAttachment.aspx?id=b84aeaba-cf14-416c-9605-67f4102206ec

[3] Ofgem approval of EWIC Access Rules and Charging Methodology Statement 2015
https://www.ofgem.gov.uk/publications-and-updates/approval-modified-access-rules-and-notice-respect-charging-methodology-east-west-interconnector-2015

Note also that FCA GL Article 31.1 – Type of long-term transmission rights – indicates that the product type can be FTR Options or FTR Obligations but not both. FCA GL Article 31.3 also states that no later than 6 months after entry into force of the FCA GL (i.e. by December 2016), there must be a joint proposal issued for consultation by the TSOs for the type of long-term transmission rights to be issued. EIL will take into account the outcome of this consultation when submitting the proposal for consultation during the latter part of 2016.

ASSESSMENT OF ITEMS (A) AND (B) – AVAILABILITY OF RULES AND SYSTEMS

The timelines in the latest draft of the FCA GL are important to consider in the context of the product type selected. As indicated in Appendix A of the consultation paper dealing with Policy Implementation Process, it is reasonable to assume the FCA GL will come into force in June 2016.

Timelines for the delivery of the final approved HAR and the associated SAP are provided for in the rules. It is our expectation that the timelines will follow the following practical implementation once the FCA GL enters into force.

Simple Overview of Single Allocation Platform Implementation

	2016			2017				2018				2019			
	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
FCA Guideline Entry Into Force															
FCA Guideline Article 51 - HAR		FTR Obligation Rules													
NRA Approval of HAR						NRA Approvals									
FCA Guideline Article 49 - SAP Rqmts								SAP Rqmts							
NRA Approval of SAP Functional Rqmts										NRA Approvals					
FCA Guideline Article 50 - Establish SAP												SAP Final Establishment			
I-SEM FTR Auction Commencement															
I-SEM Go-Live															

Table 1: Implementation Timelines of the Single Allocation Platform

A more detailed explanation of the above timeline is provided below:

- FCA GL Article 51 – Introduction of Harmonised Allocation Rules (HAR) – currently states that within 12 months of entry into force, the rules will be submitted to the NRAs for approval (i.e. Q2 2017). It is during this timeframe that the FTR Obligations rules will be developed at the EU level. A further six months should then be allowed for NRA approval (i.e. Q4 2017). Once approved, these rules could potentially be implemented on any existing regional early implementation platforms (of which JAO is one) assuming all stakeholders were in agreement with such an investment.
- FCA GL Article 49 – Functional requirements for the Single Allocation Platform (SAP) – currently states that within nine months of entry into force, the requirements for the establishment of the SAP would be submitted to the NRAs (March 2017). This timeframe itself is at odds with Article 51 which is when the rules governing the requirements will be submitted, so we expect the final version of the FCA GL to include a target timeframe for Article 49 to be soon after the NRA approval of the rules from Article 51 (say 6 months which brings us to Q2 2018). NRA approval of these requirements would then be required (i.e. Q4 2018).
- FCA GL Article 50 – Establishment of the SAP – currently states that no later than 12 months after the NRA approval of the requirements as per Article 49, the SAP would be up and running. This is very challenging particularly if a procurement exercise is required for the EU platform to be developed. It would then be Q4 2019 when the fully functioning SAP is in place. This could be a suitable point in time for considering the adoption of FTR Obligations in a structured fashion.

To date, the pan-European HAR developed as part of an early implementation of the FCA GL include FTR Options and Physical Transmission Rights (PTRs). The focus of the Joint Auction Office (JAO), which is located in Luxembourg and caters for the majority of European TSOs long-term capacity allocation needs, is to deliver an allocation platform which can offer FTR Options and PTRs, but not FTR Obligations. It is expected that this will remain the case until formally approved FTR Obligation rules are available for development within the JAO platform solution.

The implementation of FTR Obligations within the I-SEM timelines is therefore a significant challenge. In the absence of rules for FTR Obligations it is not possible to fully assess implementation options to meet the initial I-SEM timeline associated with FTR Obligations. We would not recommend the development of I-SEM specific rules for FTR Obligations as this would result in the I-SEM/GB border being non-compliant with the Harmonised Allocation Rules which have been approved by the CER and Ofgem on 15th October 2017.

ASSESSMENT OF ITEM (C) – BUSINESS READINESS COMPLEXITY

As stated previously, the HAR is now available for FTR Options but not for FTR Obligations.

If FTR Options are selected for the I-SEM/GB border, there will be a business readiness effort required to modify the arrangements with customers. EIL, together with its colleagues from Moyle, IFA and BritNed, are in detailed discussions regarding joining the JAO auction platform which will be allocating FTR Options on European borders by December 2015. This will involve joining JAO, changes to internal business functions, and developing a solution for the shorter term operational requirements of interconnector data flows. This is achievable within the current I-SEM target delivery timeframe for the auction platform solution by March 2017.

If FTR Obligations are selected for the I-SEM/GB border, there will be a more complex and resource intensive business readiness effort required. FTR Obligations rules would need to be developed. A decision will be required on whether to write these rules specifically for the I-SEM/GB border or to work together with our colleagues in ENTSO-E to write these rules for the HAR.

The JAO platform will not have FTR Obligations software modifications available for March 2017 unless the Harmonised Allocation Rules have been developed and approved for FTR Obligations well in advance. It is therefore likely that a local/regional solution would be required for an FTR Obligations allocation platform for the interim period between March 2017 and the anticipated commencement of the Single Allocation Platform in December 2019.

As stated in section 4 of the consultation, there is the requirement for a clearing house solution for FTR Obligations. Setting up a clearing house or procuring the services of an existing clearing house will reduce settlement risks, but will also require an additional level of complexity in the establishment of the I-SEM forwards solution.

ASSESSMENT OF ITEM (D) – COST OF COLLATERAL

Cost of collateral will be similar for FTR Options as is currently in place for the physical transmission rights (PTRs) that exist within the SEM.

For FTR Obligations there are a greater number of transactions and volumes procured by participants. If a clearing house function is established to net offsetting transactions between multiple counterparties, the clearing house will require collateral deposits and will need to monitor the credit worthiness of the participants and may need to provide a guarantee fund that can be used to cover losses that exceed a defaulting clearing participants collateral on deposit. What will be required of participants is a greater level of credit cover which incurs cost. This will be a barrier to entry for customers as the credit cover requirements will be higher than those required for FTR Options.

ASSESSMENT OF ITEMS (E) AND (F) – ACCESSABILITY / FAMILIARITY TO CUSTOMERS

If there are higher costs incurred by participants in the FTR Obligations solution, this will become a barrier to entry for smaller participants.

As there is limited familiarity with FTR Obligations in Europe, the appetite to avail of these products may be lower than it would be for FTR Option. This will have a negative impact on cross-border competition.

The Baringa assessment (slide 45) makes the following points:

- Current physical products in SEM are more like FTR options and are typically used by SEM suppliers to hedge/source their peak demand. Today’s auction bidders in the GB-to-SEM direction are likely to price based on their peak requirements.
- Historically, other interconnectors (e.g. IFA, BritNed) have also used physical products which are more like FTR options. Hence, experience in SEM and across Europe is of options not obligations.

- Buyers of obligations may be risk-averse and over-discount in bidding for FTRs due to the open-ended exposure to reverse payments. This risk aversion is likely to be comprised of a) the need to provide collateral to cover credit risk and b) lack of experience and familiarity with obligations.

ASSESSMENT OF ITEMS (G) AND (H) – LIQUIDITY AND NETTING

FTR Obligations will only be possible to implement locally (JAO will not be available for FTR Obligations until the HAR is developed to include FTR Obligations) and will result in far fewer market participants across Europe participating in the I-SEM. This will have a negative impact on competition in the FTR market and will only serve to increase profits for the few market participants who do select to operate within the I-SEM market in advance of the single allocation platform being available.

The Baringa assessment (slide 45) makes the following points:

- Netting, a theoretical advantage of Obligations, is unlikely to be significant given that a) the optimal direction of flow is likely to be predictable, once the year-ahead stage has been reached, and b) there is likely to be broad market consensus of this. It is possible that players with opposite positions (long in I-SEM and short in GB on the one hand, and short in I-SEM and long in GB on the other) will have incentives to flow in opposite directions due to transaction costs, but these are likely to be relatively minor compared with market price differences.

ASSESSMENT OF ITEM (I) – MARKET STABILITY

The Baringa assessment (slide 45) makes the following points:

- If there is a stable 1-way delta between market prices, the theoretical fair values of Options and Obligations converge, but we judge Options to be favourable for the reasons of risk-aversion and lack of familiarity with Obligations.

EIL would add that the new I-SEM will not be an established market for some time, and perhaps delaying the adoption of FTR Obligations to when the single allocation platform is in place will facilitate a timeframe within which the stability of the market can be created, and a review of the pros and cons of the product type can be revisited in the context of the wider European market benefits.

2) SINGLE FTR PRODUCT OR PER INTERCONNECTOR FTR PRODUCT

2. What arrangements would be preferred: one FTR between the I-SEM and GB or one FTR per interconnector?

EIL is open to either implementation solution.

With as single product for the I-SEM/GB border, there may be a higher valuation of the FTR by market participants as the curtailment risk is shared, reducing the overall impact of curtailment risk for customers. There are some disadvantages with separate products per interconnector, such as lower liquidity and potentially lower valuation of the products due to the treatment of losses and the perceived increased curtailment risk for FTR holders.

Separate products per interconnector may prove a simpler solution to implement, however EIL would disagree with the arguments presented in the consultation paper around revenue sharing complexity being a barrier to one product option selection over the other. The auction platform administrator will make payments to the interconnector owners based on the portion of the product sold, and where curtailment occurs, this can be addressed on a per interconnector curtailment compensation assessment. Any required agreement in this regard should be achievable. The day-ahead market coupling algorithm will make separate payments per interconnector as per the market design decisions previously announced. There would be no ex-ante revenue sharing apportionment needed for the long-term auctions and for the day-ahead timeframe there would be no congestion rent sharing agreement as the interconnectors are modelled separately in the day-ahead timeframe.

If losses and ramping are applied to FTR pay-outs for long-term FTR holders, then one FTR per interconnector will be required as the products have different attributes. If losses and ramping are excluded from the FTR pay-outs then there is no strong argument to separate them.

From a ramping perspective EIL argues for a removal of the ramp restriction from both the long-term and day-ahead timeframes.

From a losses perspective, the revenues received from the day-ahead market coupling algorithm will be lower for EWIC than for Moyle due to the higher losses incurred on EWIC. This will result in EWIC using more of the revenues received from the long-term congestion revenues to cover the additional cost of compensating FTR holders in a single product solution and in the separate product solution where losses are not discounted from the long-term FTR pay-outs.

The consultation minded to decision to separate the products includes a point about maintaining existing arrangements to stagger auction dates to enable market participants to manage their exposure to procurement of capacity. This arrangement of itself introduces inefficiencies in the handling of long-term capacity auctions. Market participants have indicated a greater preference for the EWIC auctions to be aligned with the Contracts for Differences (CfD) auctions held in both Ireland and Great Britain where possible. This would better facilitate hedging of the end-to-end positions held in both markets. Coordination between EWIC and Moyle is working, but does limit flexibility to address the market participants needs in this regard.

The ability to *"countertrade (in the intraday market or through specific contracts with generators and/or suppliers)"* is referred to in 4.1 of this consultation which is acknowledged as not permitted under current licence conditions. We expect the System Operators to be able to use the Balancing Mechanism to effect Redispatching (as per the CACM Regulation 1222/2015 requirements) while the use of out-of-market contracts is subject to further consideration within the I-SEM Market Power workstream.

EIL's current licence excludes any engagement in countertrading as per the CACM Regulation 1222/2015 requirements. EIL would welcome the opportunity to further discuss opportunities to engage in financial risk management in order to mitigate financial exposures such as those incurred due to imbalance in the event of outages after the day-ahead firmness deadline.

3) TREATMENT OF LOSSES, RAMPING, CURTAILMENT

3. Should any of the following be discounted from the FTR product pay-outs?

- **Interconnector transmission losses;**
- **Ramping constraints;**
- **Curtailment risks**

The current version of the FCA GL Article 35.3 – Principles for long-term transmission rights remuneration states: 'In case transmission losses and/or ramping rates on interconnections between bidding zones have been included in the day-ahead capacity allocation process, they shall be the only allocation constraints to be taken into account for the calculation of the remuneration of long-term transmission rights'.

The final decision should be aligned with the FCA GL provisions.

INTERCONNECTOR TRANSMISSION LOSSES

The Baringa analysis Reference Case (page 38 of the attached Baringa report) shows that the costs of losses on EWIC are approximately €11m/y. The key market design question is whether the FTR holders will incorporate the full cost of these losses into the auction bids for long-term capacity auctions.

EWIC		2017 SEM	2017 I-SEM	2018	2019	2020	2021
Gross Margin	*Million €*	3.8	17.4	63.1	56.1	63.2	64.1
FTR option payout	*Million €*		20.3	74.5	67.7	74.8	76.0
Gross margin exposure due to FTR	*Million €*		-2.9	-11.4	-11.6	-11.6	-11.9
Cost of ramping	*Million €*		0.0	0.1	0.1	0.2	0.2
Cost of part loading	*Million €*		0.0	0.2	0.4	0.6	0.7
Part loading %	*%*	74%	6%	9%	15%	19%	22%
Cost of losses	*Million €*		2.8	11.1	11.1	10.8	11.0
Cost of losses with a linear function (No intercept)	*Million €*		2.9	11.2	11.2	10.9	11.1
Max daily FTR obligation exposure	€		-	-	25,381	29,253	-

Table 2: Baringa Assessment of EWIC Costs for Losses, Ramping and Part Loading

In all cases, the cost of losses will be incorporated into the lower revenues received by EWIC from the day-ahead market coupling algorithm. Where FTRs pay-outs do not have losses discounted, a portion of the congestion revenues received from the long-term capacity auctions will be added to the revenues from the day-ahead market coupling algorithm to make the full FTR pay-outs. For interconnectors with higher losses, the amount of long-term capacity auction congestion revenues used will be higher. This places the risk on interconnector owners.

Note that if a single FTR product for the I-SEM/GB border is selected, then FTR pay-outs will not have losses discounted. With separate FTR products per interconnector, there is more flexibility in the handling of losses.

Where separate FTR products per interconnector are selected, the losses can either be treated in the same way as described above for the single product per border, or by discounting them from the FTR product pay-outs. The cost of losses are still incorporated into the lower revenues received by EWIC from the day-ahead market coupling algorithm in either scenario. Where losses are discounted from FTR product pay-outs, a lower amount of congestion revenues received from the long-term capacity auctions is used to fully compensate FTR holders, and there is less risk for the interconnector owners. The FTR holders will, in turn, model the cost of losses into their bids and the bid price for the product will be lower leading to lower long-term congestion revenues. The costs of losses to the interconnector owner are passed through to the FTR holder.

If FTR holders model the losses efficiently then the outturn long-term auction revenues for the interconnector owner and hence the benefit to the TUoS customer should be the same. It is therefore perhaps more important to focus on the benefit of the single product per border or separate products per interconnector.

It is noted for reference, the decision taken in the I-SEM ETA Detailed Design – Building Blocks Decision Paper executive summary and section 2.4 sets out the treatment of losses in the day-ahead market for interconnectors as separate loss factors, and there will be no review the existing TLAF approach to assessing losses within the I-SEM.

RAMPING CONSTRAINTS

There is no specific reference in the I-SEM day-ahead market design decisions for the handling of ramp rates in the day-ahead timeframe. The working assumption of the I-SEM EUPHEMIA modelling workstream has been to keep ramp rates at the 5 MW/min as is currently in operation on both EWIC and Moyle interconnectors.

EIL is of the view that ramping constraints should not be included in the day-ahead timeframe and hence should not be included in the FTR product settlement arrangements. Ramp restrictions should be removed for interconnectors in the day-ahead scheduling algorithm, other than taking the maximum operating ramp characteristics of interconnectors into account. The EWIC currently has a maximum operating ramp rate set at 999 MW/s (i.e. interconnector technical ramp restrictions are inconsequential and not relevant to the discussion).

The day-ahead market coupling algorithm will establish feasible schedules based on the bid profiles of market participants, as such, the interconnector physical reference programmes should reflect feasible flows. Should the system operator require the interconnector to ramp at a slower rate, then this could perhaps be procured as a ramping service within the future DS3 arrangements.

If ramp restrictions are removed from the interconnectors, any system operator imposed ramp restriction would come at a cost to the system operator. This would act as an appropriate incentive to minimising ramp restrictions and optimising the use of the interconnector.

If a regional ramping solution were available in the day-ahead market coupling algorithm, which allows the interconnectors to be ramped to the maximum combined level at all times, it would deliver a substantial benefit to the markets and would deliver higher revenues to the interconnector owners from the day-ahead market coupling algorithm which would in turn be available to compensate FTR holders.

The Baringa analysis outlines where costs attributed to ramping restrictions manifest themselves. The chart below (Baringa analysis slide 32) provides an example of the high frequency of change in direction of flow on the interconnectors when price spreads are tighter.

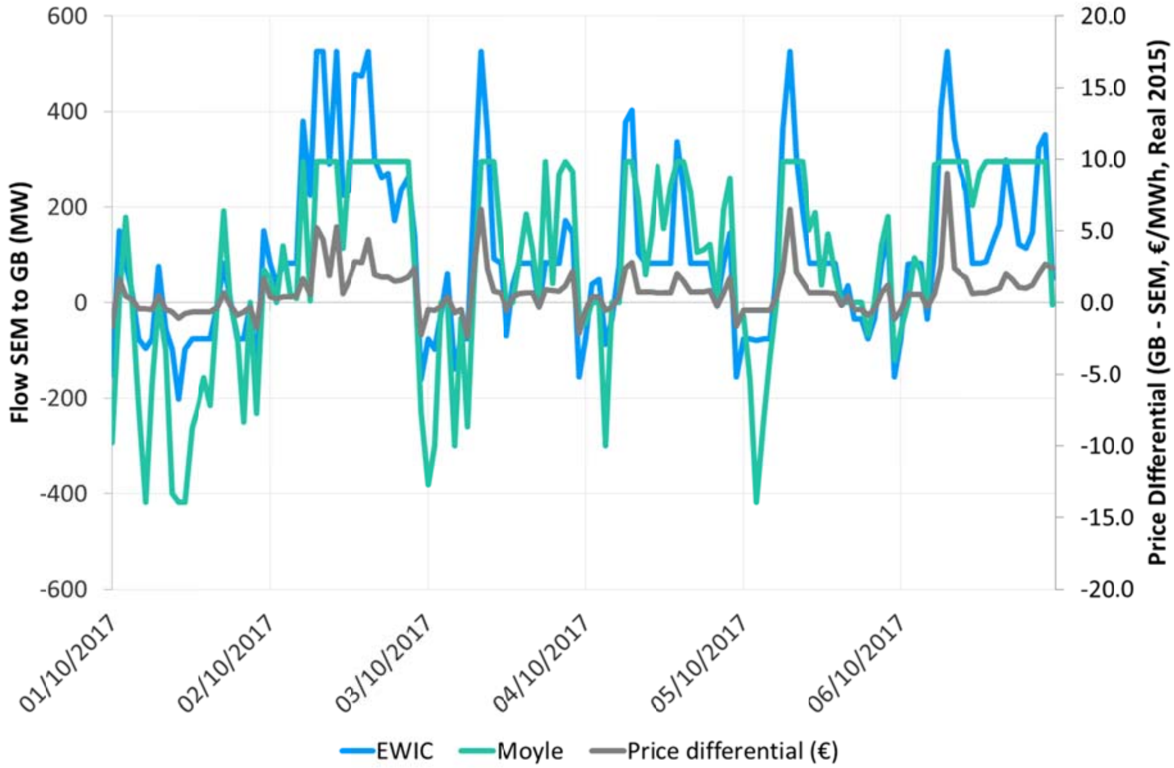


Figure 1: Baringa Assessment of Ramping - Downside Case

In the Baringa Downside Case, where the price spreads are closer, the level of ramping is high, however the lower price spreads does soften the cost impact of ramping restrictions.

The SEM Committee identified in its impact assessment of the I-SEM HLD that a substantial amount of the benefits to consumers from the I-SEM will come from more efficient use of the interconnectors in the day-ahead and intraday timeframes. It is important that the detailed design decisions capture these benefits.

EIL notes the use of 5% for the ramp rate used in the assessment of the market coupling algorithm prior to flowing power on EWIC. This is inconsistent with the SEM-C decision to use TLAF values when modelling losses.

CURTAILMENT RISKS

Regarding curtailment risks, the final decision should be aligned with the FCA GL provisions.

The ultimate exposure to curtailment risk for market participants is considered low given the level of firmness currently incorporated into the FCA GL.

The consultation document refers to the curtailment firmness cost arrangements influencing whether the products are separate per interconnector or a single product. EIL is not in agreement with this concept as the firmness costs will be the same for individual interconnectors regardless of whether the product is shared or separate. The auction platform administrator will collect the correct amount of curtailment compensation payment from each individual interconnector owner dependent on the level of capacity that was curtailed on each interconnector. This will then be distributed to the FTR holders as appropriate.

Where curtailment costs are incurred by EWIC it is useful to differentiate between curtailments due to technical issues with the interconnector and those curtailments due to system operator system security reasons. Where the curtailment is due to system operator system security reasons, these curtailment costs should be covered by the system operator rather than the interconnector owner.

4) CONSIDERATIONS WHEN DEVELOPING THE AUCTION PLATFORM

4. What are the important issues to be considered in deciding on the development of an auction platform?

EIL has considered the following important issues as part of the considerations for the auction platform solution:

- **Customer access – increasing competition:** JAO has over 150 customers trading on the various interconnectors throughout Europe. These customers will have much greater access opportunities to the I-SEM market. Many of the existing EWIC customers are also already registered with JAO for the purpose of trading with other interconnectors.

- **Customer experience – single point of contact:** Customers will have one interface and contract with the JAO platform for the long-term capacity auction process including registration, credit cover, capacity auctions, capacity returns, customer support, settlement, and invoicing.
- **EU Target Model objectives:** It is important to consider the intent of the EU target model and the FCA GL intentions, which is to put in place a single point of contact for customers to participate in long-term capacity allocation across Europe. This will not be facilitated if we select a local auction management platform solution to facilitate FTR Obligations.
- **Harmonised Allocation Rules:** The rules governing the allocation of capacity must be fully complied with as part of the implementation solution. It would be beneficial to avail of a solution which has already achieved this if possible.
- **Longevity of the allocation platform solution:** If a local solution is selected, then the likelihood is an immediate commencement of a new project to transfer to the Single Allocation Platform (SAP) would be required on I-SEM go-live. The JAO solution will offer a more enduring solution and may in fact become the basis for the future SAP.
- **Product Type Selected:** If FTR Obligations are selected, then the local platform will be the only solutions available. FTR Options provides a more straightforward path to successful implementation and would be available on all options.
- **Efficiencies in scale and cost:** The greater the number of TSOs and interconnectors involved in the platform solution the greater the efficiencies and the lower the cost to implement. JAO is the best option in this regard. Implementation and operations costs will be far higher for a local solution (which would be the only choice for FTR Obligations) given that the end-to-end solution would need to be developed solely for local needs. The administration of long-term arrangements would also remain local, including all associated customer registrations, credit cover management, auction management, secondary market, settlement, invoicing, clearing house interfacing, etc.
- **Elimination of duplication of effort:** This relates to the longevity of the platform solution and to the fact that much of the work associated with the development of the solution has already been completed by the JAO. Implementing a local solution would be a duplication of work already carried out elsewhere.
- **Procurement:** There are procurement considerations involved for each platform option.

- **Data Transparency and REMIT obligations:** The implementation of data interfaces to the transparency platform and for REMIT data submission needs to be considered.
- **Interfaces with future EU wide systems:** As part of the implementation of the CACM Regulation and Electricity Balancing Guidelines, there are regional and European wide mechanisms being put in place, some of which will require interfaces to the platform solution selected.

If the decision is to opt for FTR Obligations, then we will be required to develop a local solution and local rules to govern the auction platform for the I-SEM/GB border. This is not recommend as it would result in isolation of this market from the wider European long-term capacity allocation approach, and would close the door to a much greater potential competitive influence available within the +150 customer base which the JAO platform currently enjoys.

5) PREFERRED APPROACH FOR FTR AUCTION PLATFORM

5. What is the preferred approach in relation to the establishment of the I-SEM FTR auctioning platform?

EIL is working with Moyle Interconnector, EirGrid and other regional stakeholders, to ensure that an appropriate solution is implemented within the I-SEM timescales. Additional industry feedback in relation to that process is welcome and we will endeavour to take relevant comments into account. The SAP envisaged in the FCA GL would be the EIL preferred implementation approach if it was available within the I-SEM timeline. As the SAP will not be available for March 2017, EIL is progressing with joining the JAO platform once detailed feasibility of the approach has been confirmed.

EIL is currently engaging with the other interconnectors in the FUIN[4] Region (Moyle Interconnector, National Grid Interconnectors Limited, BritNed, and RTE) in carrying out a joint feasibility of the Joint Allocation Office (JAO) approach.

[4] FUIN refers to a region comprising France, UK, Ireland, Netherlands.

We would make one clarification to the consultation text regarding the JAO status. The consultation states that *"The JAO platform is seen by European stakeholders such as ENTSO-E, ACER and European Commission as a project leading to the SAP"*. Practically speaking this is correct, however, the JAO platform has not been formally designated as the early implementation project for the SAP. The decision on the SAP may not be taken until well after the FCA GL comes into force. Part of the feasibility assessment includes the full scope of solution requirements, which are wider than JAO will be able to provide in advance of I-SEM go-live, and procurement requirements.

The responsibility for implementation of the allocation platform currently rests with the SONI and EirGrid Interconnector Limited licensees, and milestones regarding implementation are defined in the FCA GL as the TSO's responsibility. EIL will ensure clear communication with stakeholders on the delivery of the allocation platform solution as it develops.

APPENDIX – BARINGA MODELLING ANALYSIS

GB - Ireland Power Market Modelling

Interconnector analysis

Client: EirGrid
Date: 8th October 2015
Version: Final results

Reputation built on results

Contents

Methodology

Baringa

Baringa power market model

Baringa power market model

- At the heart of our market modelling lies a dispatch 'engine' based on a detailed representation of market supply and demand fundamentals at an hourly granularity
- We run our models on commercially available power market modelling software (Plexos). It is used globally by power market participants, regulators, and analysts for modelling power systems of all characteristics
- For hydro generation units, the software calculates the value of energy stored within an associated reservoir, the 'water value'. This value is used to optimally dispatch the hydro generators

Scenario inputs

Base Case

- Fuel & carbon prices
- Demand (growth & shape)
- Plant build
- Plant retirement

Baringa EU generator dataset

Detailed plant-level database

- Installed capacity
- Efficiencies
- Operating costs
- Operational constraints

PLEXOS

Detailed generation dispatch model

- Hourly generation dispatch
- Model interconnected markets
- Optimisation of operational constraints such as start costs, ramp rates and heat rate curves
- Hourly wind and solar profiles based on historic data
- Hydro and pumped storage
- Scheduling of maintenance and unplanned outages

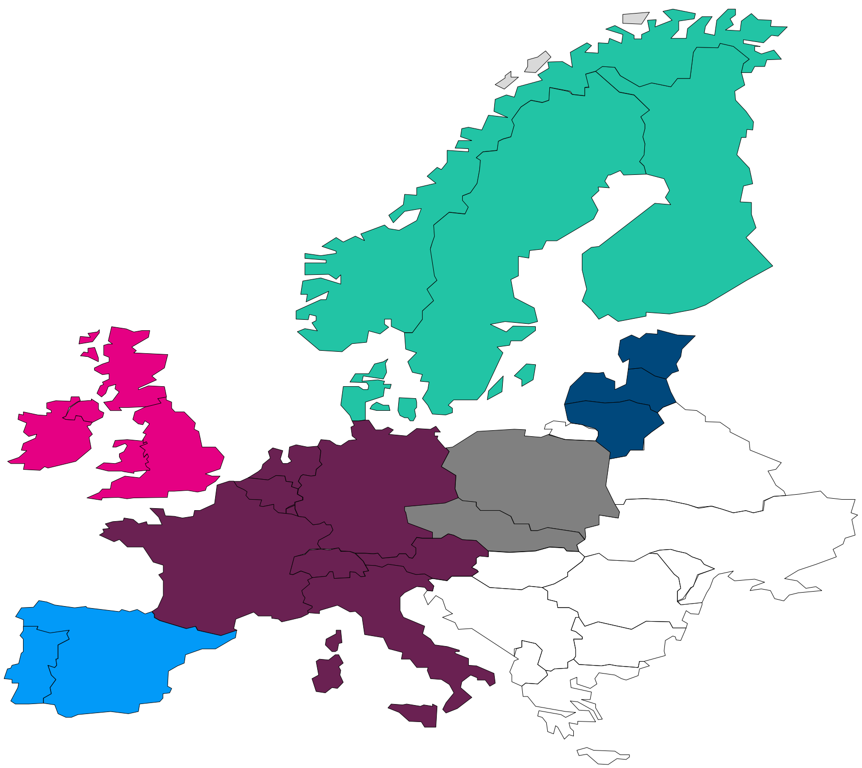
Outputs

- Power prices
- Generation schedules
- Emissions
- Dispatch costs
- Wholesale revenues and gross margins
- Imports & exports

Methodology

Pan-European Model

Pan-European Model

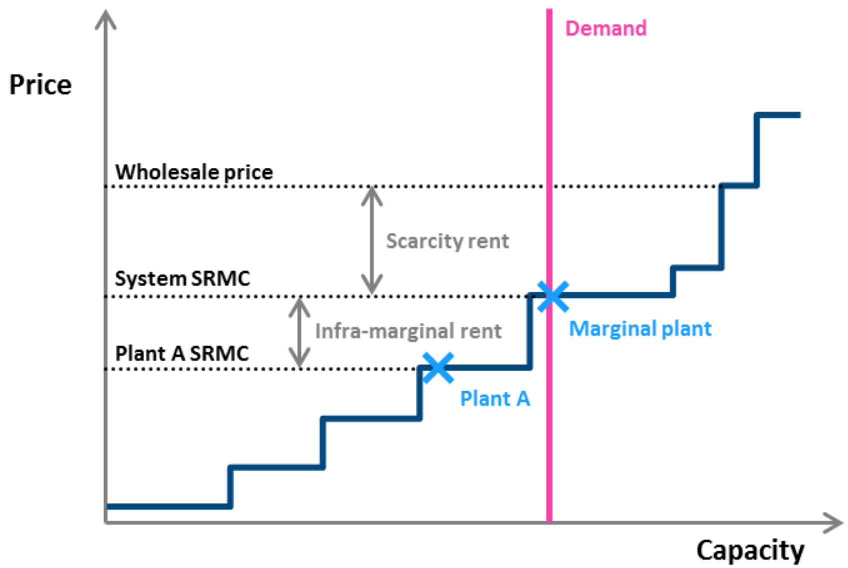


- The Baringa Pan-European Power Model (PEPM) features **detailed dispatch of the wholesale electricity markets of western Europe**:
  - Great Britain and Ireland (the Single Electricity Market – SEM)
  - Nord Pool (Denmark, Finland, Norway, Sweden and the Baltic countries)
  - Central Western Europe (Germany, Austria, the Netherlands, Belgium, Luxemburg and France)
  - Switzerland
  - Iberia (Spain and Portugal)
  - Poland
  - Czech Republic and Slovakia
  - Italy
- We determine economically rational **market dispatch**: *within* each market network issues and energy balancing are not analysed in the model; but *between* markets we do account for limitations on power transfer capacity
- PEPM has been backcast for recent years
  - Historical commodity prices, demand, interconnector NTCs have been used
  - Actual plant availability data has not been used

Methodology

Price formation

- The system short run marginal cost (SRMC) is the marginal cost of the marginal generation unit in each hour
- Plant with lower SRMCs than the marginal generation unit will earn profit termed 'infra-marginal rent' which is the difference between their SRMC and system SRMC
- 'Scarcity rent' is added to the system SRMC to calculate final hourly wholesale prices
- We treat scarcity rent as a function of hourly capacity margin – the tighter the capacity margin, the higher the scarcity rent
- This reflects the scarcity value of power on an hourly basis, and is important in delivering a return on capital
- We correlate scarcity rent to the capacity margin, but in reality it is the result of many inter-related factors

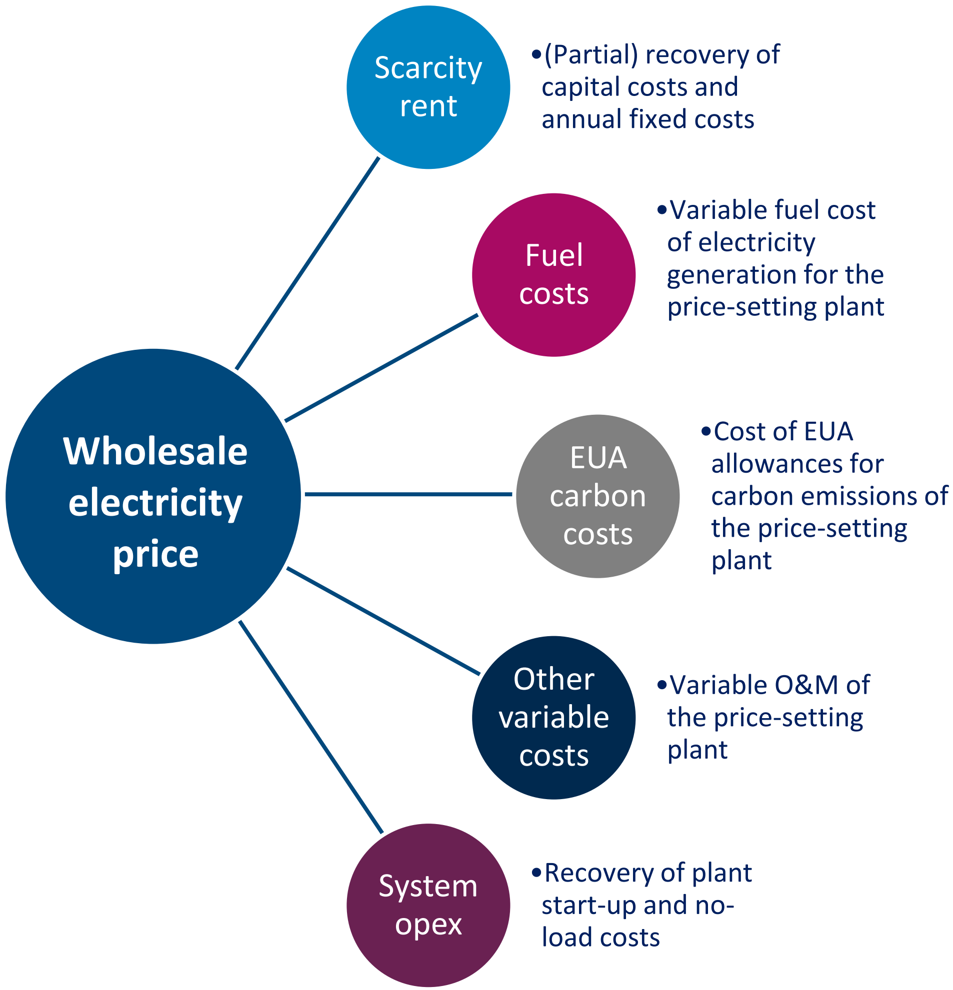


Methodology

Wholesale power price components

Baringa power market model

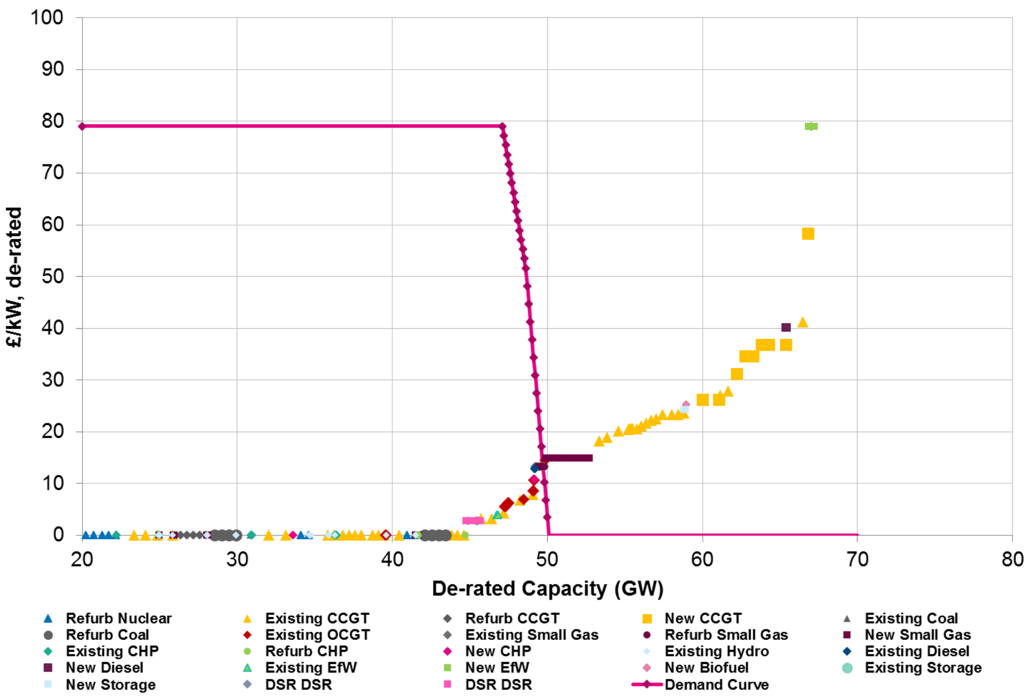
- Wholesale electricity prices can be broken down into five basic components
- These components are likely to be present at some level in a sustainable wholesale price
  - It is important to note that the wholesale electricity price is subject to year-to-year variation
  - Short-term events may mean that in isolated years, some components (especially scarcity rent, but possibly also system opex in a highly competitive situation) may not emerge
  - However, such a situation is unlikely to be sustainable in the long term
- Interactions between price components are complex with some having a greater price impact than others
- We assume that behaviour in the wholesale market is not directly affected by the presence of a capacity market (but is affected by the volume and make-up of physical capacity)
- Generators still price in a ‘scarcity rent’ component which is based on the capacity margin



Methodology

Capacity mechanism

De-rated Peak Capacity Margin (DRPCM) (%)



Methodology

- To complement the PLEXOS market model and LCF expenditure model, our Capacity Market (CM) auction model simulates the annual capacity market auction. This model is used to project annual CM clearing prices, new capacity build and capacity retirements for each scenario. Separate models have been developed for the GB CM and the I-SEM CRM
- Generator bids are assumed to be based on their “missing money”. Bidding behaviour or portfolio effects are not considered
- The missing money is based on the energy market gross margins for each respective generator from the relevant market model scenario, with generator specific TNUoS charges and technology specific fixed costs and ancillary revenues then included to get each plant’s year on year missing money. This is assumed to be their CM bid
- New entrant capacity bids their annuitised capital costs, as well as their view on forecast 15 year revenues is considered
- The interaction between the market model energy rents, IED decisions, CM payment clearing prices is all internally consistent and is an iterative process. The process is repeated multiple times until the capacity new build and retirement decisions reach equilibrium

Methodology

Generator bidding behaviour

Generator bidding behaviour – two alternative approaches

- Generators recover their fixed and capital costs through CM and prices in the wholesale energy market are determined by the short run marginal costs (SRMC) of generation
  - Relatively low power prices in wholesale market (no fixed cost recovery)
  - Relatively high capacity auction clearing prices (fixed and capital cost recovery)

- Generators continue to price offers into the wholesale market on the basis of instantaneous demand and supply conditions.
  - The capacity margin, and the nature and ownership of available capacity, determine the bidding behaviour by generators, and the capacity auctions have no direct impact
  - The auctions have indirect impact as they determine the amount and make-up of capacity, which in turn influences scarcity premia in the wholesale market
  - The auctions are essentially a mechanism for the recovery of 'missing money' (i.e. fixed and capital costs which are not fully recovered via infra-marginal rents – the differences between the running costs of the marginal or 'last' station needed to meet demand and the running costs of each of the other stations generating – and scarcity premia in the wholesale market)

Approach adopted by Baringa in market modelling

Contents

Scenario description

Scenario formation

Scenario Assumptions

Upside Scenario

- Central-High Average Price Spreads
- High potential for Price Volatility
- High Fossil Fuel Prices
- High Carbon prices
- High penetration of intermittent RES-E

Base Case Scenario

- Central-High Average Price Spreads
- Central-Low Price Volatility
- Central Fossil Fuel Prices
- Central Carbon prices
- Surplus of low carbon electricity

Downside Scenario

- Low Average Price Spreads
- Low Price Volatility
- Low Fossil Fuel Prices
- Low Carbon prices
- Reduced investments

Scenario description

Scenario assumptions

Scenario Assumptions

- Three main scenarios are modelled to explore different long term fundamental conditions in the GB and Irish power markets
- There are no probabilities associated with these scenarios, rather each scenario is discrete and internally consistent

Base Case Scenario

- The Base case represents Baringa's central view on the evolution of the GB and Irish power markets. Under this scenario, both Governments continue to pursue a balanced energy policy, attempting to meet the sometimes competing demands of security of supply, competitive market structure, and environmental sustainability

Downside Scenario

- The Downside case considers a scenario with low commodity prices and GDP growth relative to the Base case. Lower commodity prices decrease the running costs of the marginal plant and the system's marginal price. Furthermore, we assume that the GB Carbon Price Support, currently £18/tCO2, is scrapped; and that generators do not bid 'scarcity premia' in this scenario, i.e. prices are set by short run marginal costs in all periods. These factors place downward pressure on wholesale power prices and spreads relative to the Base case

Upside Scenario

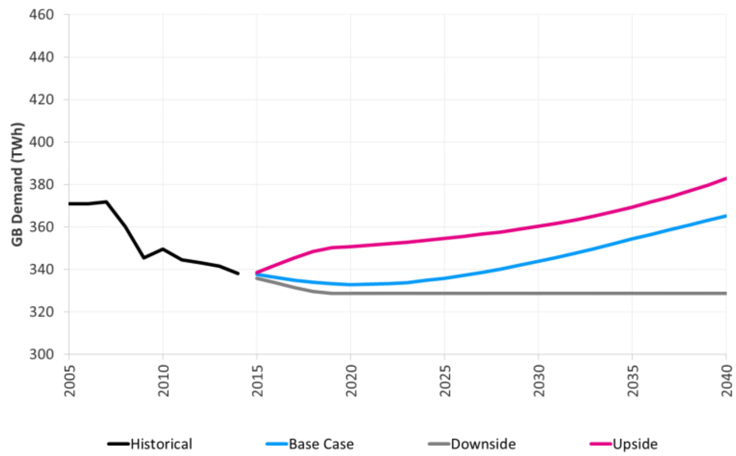
- The Upside case considers a scenario with higher oil prices and demand, with the the knock on effect of higher oil indexed gas prices and carbon prices relative to the Base case. Scarcity premia are bid into the wholesale market by generators. These factors combined lead to higher wholesale electricity prices

Contents

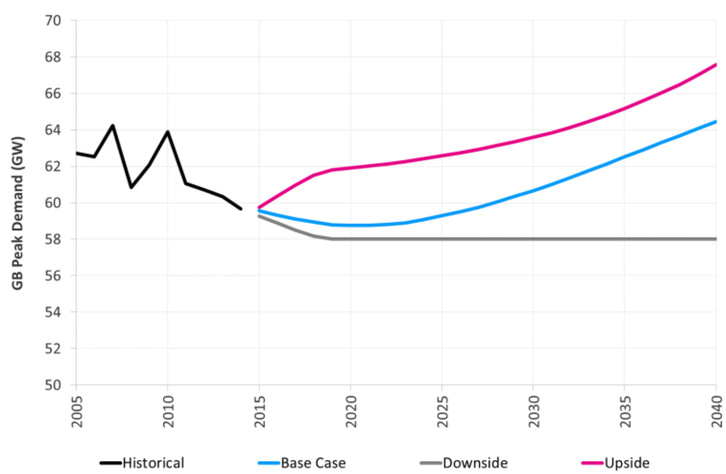
Demand assumptions

GB electricity demand growth projections

Annual Demand (TWh/annum)



Peak Demand (GW)



Demand

Annual energy requirements

- In the Base Case, the average demand growth rate of the four National Grid FES 2015 scenarios is adopted for GB
- In the Downside case, the most recent demand growth trajectory from the National Grid Gone Green Scenario is adopted between 2015 and 2019. Demand is kept flat post 2019 reflecting a world with no electrification of the transport and heat sectors and low economic activity
- For the Upside scenario, we assume that higher economic activity will lead to a slightly higher demand growth rate (0.5% average per annum). Demand is more closely tied to GDP growth in this scenario and picks up relatively quickly in the first few years when the GDP growth rate is circa 2.5% (compared with 2% from 2020)

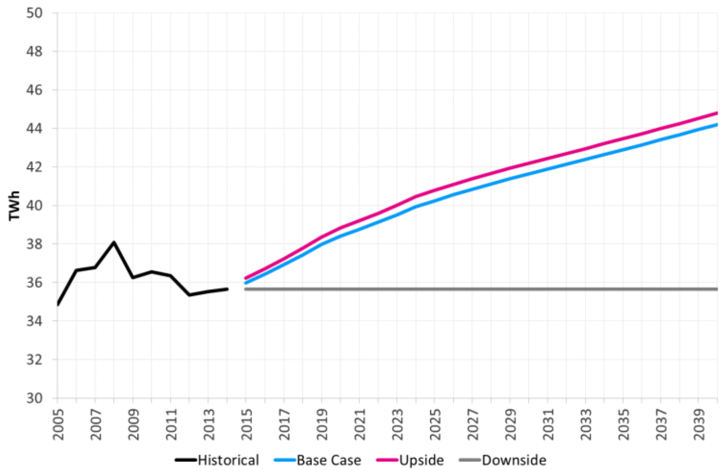
Peak demand

- Peak electricity demand is assumed to grow at the same rate as annual electricity demand.
- This is a more conservative assumption than in the FES 2015 scenarios where peak demand grows at a higher rate than energy demand in three of the four scenarios

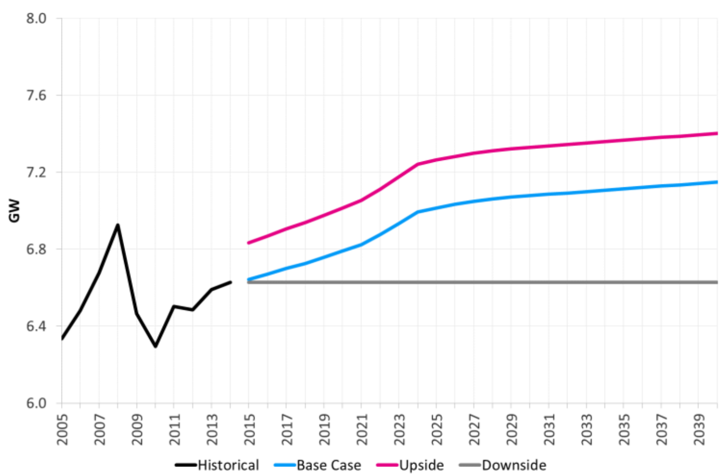
Demand assumptions

Irish electricity demand growth projections

Annual Demand (TWh/annum)



Peak Demand (GW)



Demand

Annual energy requirements

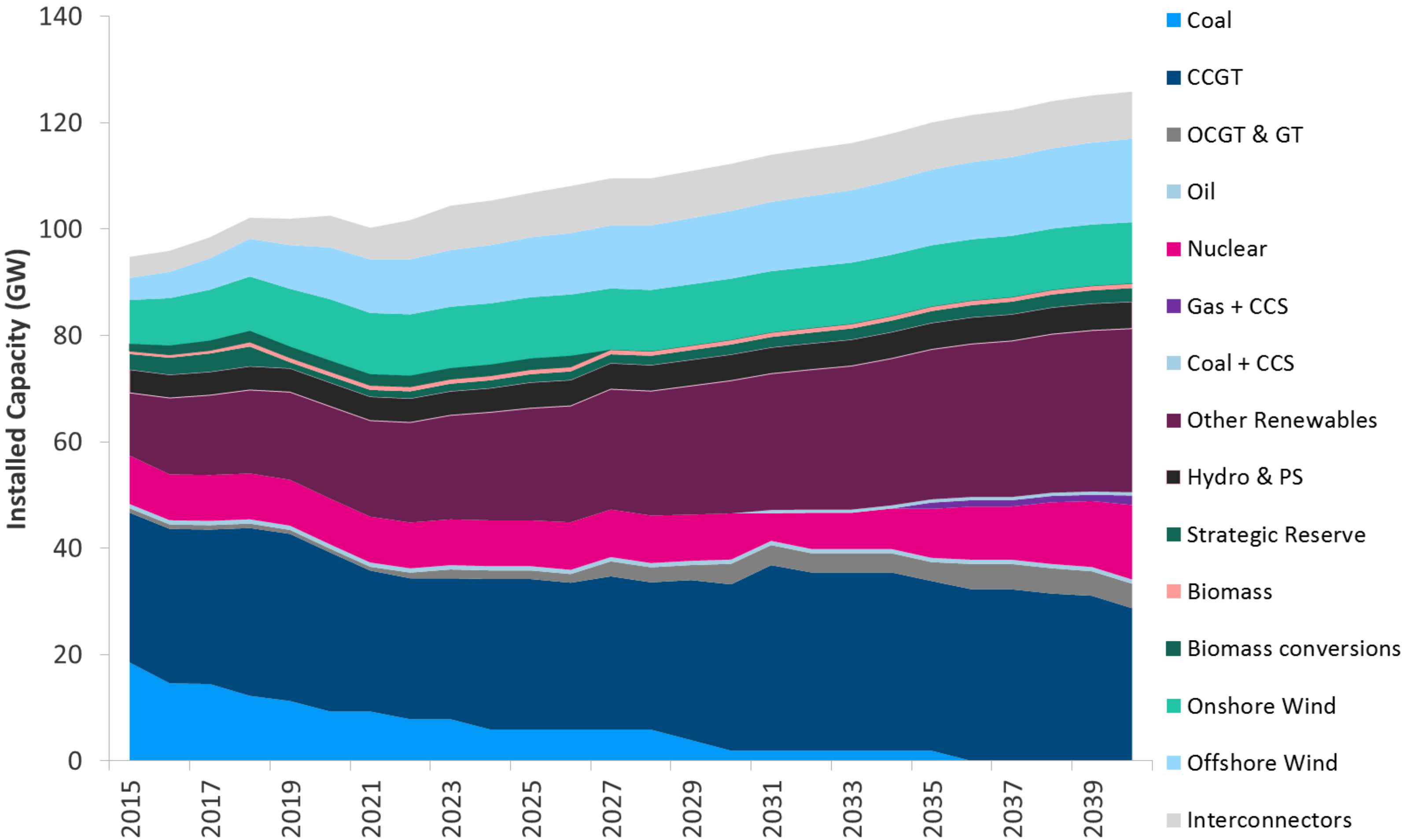
- We use the Median and Upside demand forecast from the System Operators for the Base and Upside cases, respectively. The Downside case is more conservative, with demand remaining flat at 2015 levels
- Beyond the horizon of the SO projections, the forecast for the Reference and Downside cases is derived on the basis of GDP growth and the ratio of energy demand growth to GDP growth - the 'energy intensity' ratio
- In the Reference cases we assume GDP growth of 2% from 2024, and that energy intensity falls over time to reach 50% in 2020, more in line with GB and other countries in Western Europe. This leads to energy demand growth of 1%.

Contents

GB Capacity mix

Base Case

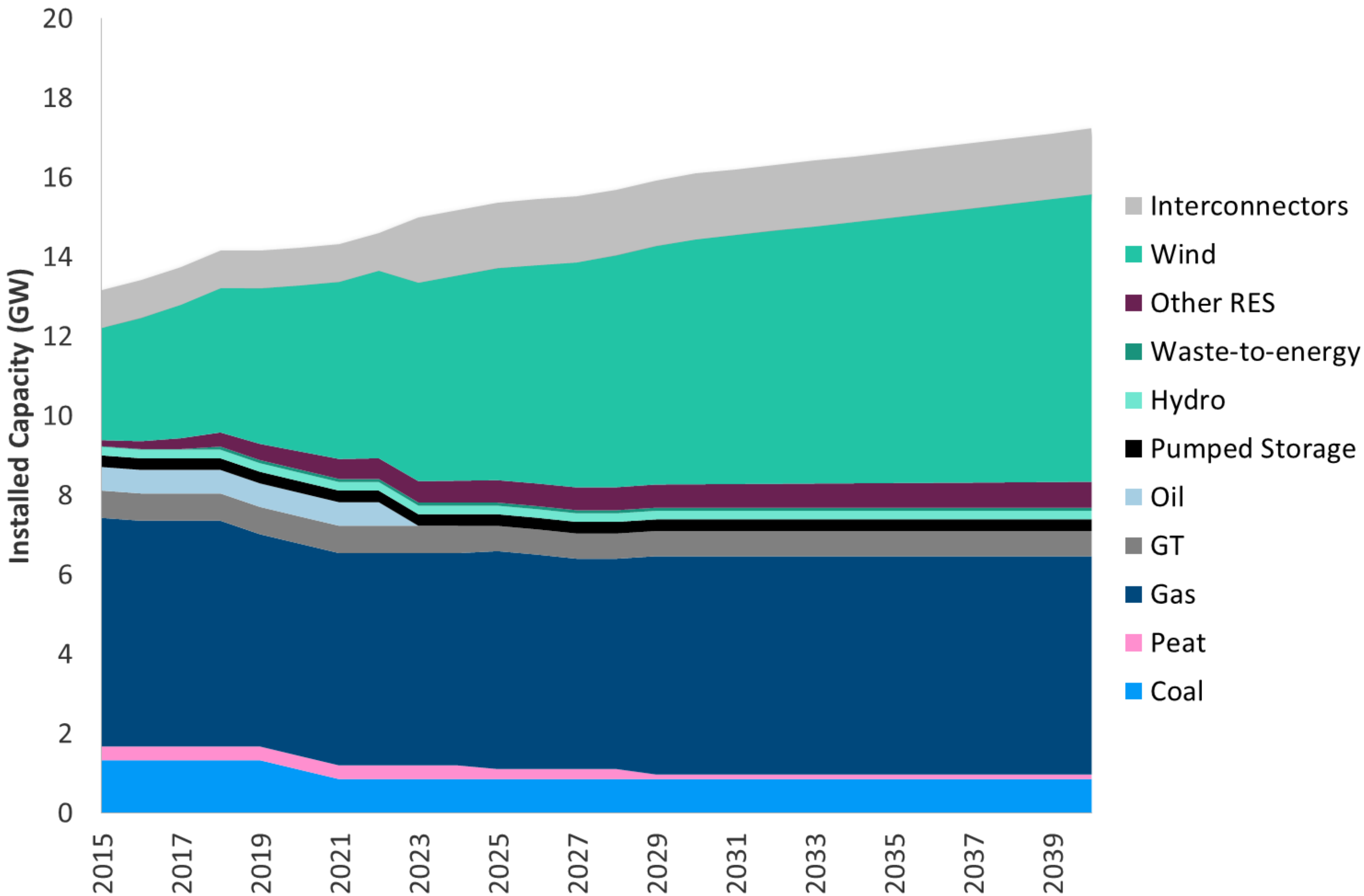
Installed Capacity (GW) (Base case)



Ireland Capacity mix

Base Case

Installed Capacity (GW) (Base case)



Contents

Interconnector assumptions

EWIC and Moyle Technical Parameters

Technical parameters (Reference Case)

	EWIC	Moyle
Max Flow (From SEM to GB)	500 MW arriving to GB	295 MW leaving NI (September - April) 287 MW arriving to GB (May – August) 80 MW from 10/11/2017*
Min Flow (From GB to SEM)	-530 MW leaving GB	-410 MW arriving to NI (April to October) -450 MW leaving GB (November – March)
Planned outages	06/09/2016 to 09/09/2016 03/04/2017 to 26/05/2017 4 days in September every year	01/04/2016 to 30/09/2016 4 days in August every year
Unplanned outages	2%	2%
Ramp up/down constraints	5 MW/min	5 MW/min

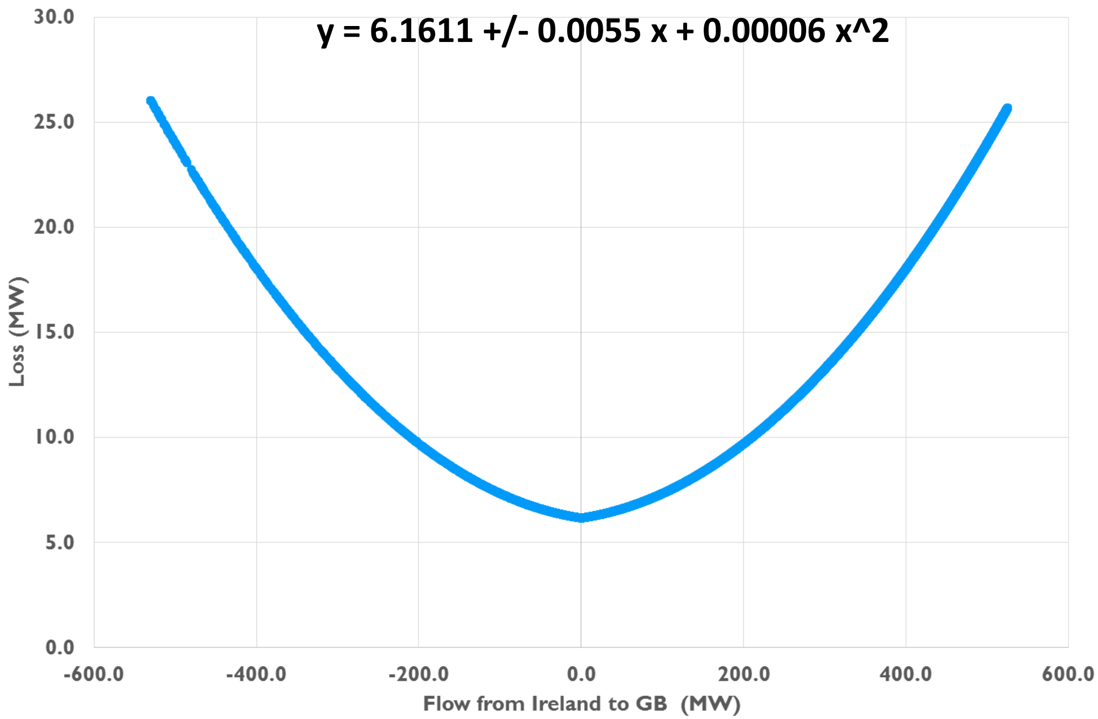
*We have also run the following sensitivities:

- Moyle @ 300 MW: Moyle max capacity remaining at 295/287 MW throughout the simulation
- Moyle @ 500 MW: Moyle max capacity remaining at 295/287 MW until the end of 2022 and 500 MW thereafter

Interconnector assumptions

Representation of losses – EWIC (quadratic form)

EWIC



Baringa Reference Case assumptions

- The loss function supplied by EirGrid for EWIC is in **quadratic** form:

  y = A*x^2 + B*x + C

- We have run a few sensitivities with the following loss equations to test their impact on the model results:
  - Removing the fixed element of the quadratic function
  - Fitting a linear function with no intercept that equals losses at full load
  - Running with no losses
- When simulating "**no losses**" we have included a very small linear term (0.1%) to eliminate loop flows on Moyle and EWIC

Contents

Interconnector assumptions

Treatment of losses and ramp rates

Reference and sensitivities

- **Reference losses**
  - Variable element (quadratic for EWIC, linear for Moyle) and fixed loss component
  - Direction specific losses
- **Variable only losses sensitivity**
  - Variable element only (quadratic for EWIC, linear for Moyle)
  - Does not include fixed losses
  - Direction specific losses
- **Linear losses**
  - Linear element only
  - Includes fixed losses at full load
  - Direction specific losses
- **No losses sensitivity**
  - Variable element set to 0.1% to avoid loop flows
- **Reference ramp rates**
  - Ramp rates of 5MW/min (i.e. 300MW change in 1hour step)
  - Ramping assumed same in both directions
- **No ramp rates sensitivity**
  - Ramp rate unconstrained (full import to full export in 1hour time step)

Scenario modelling

Simulation runs

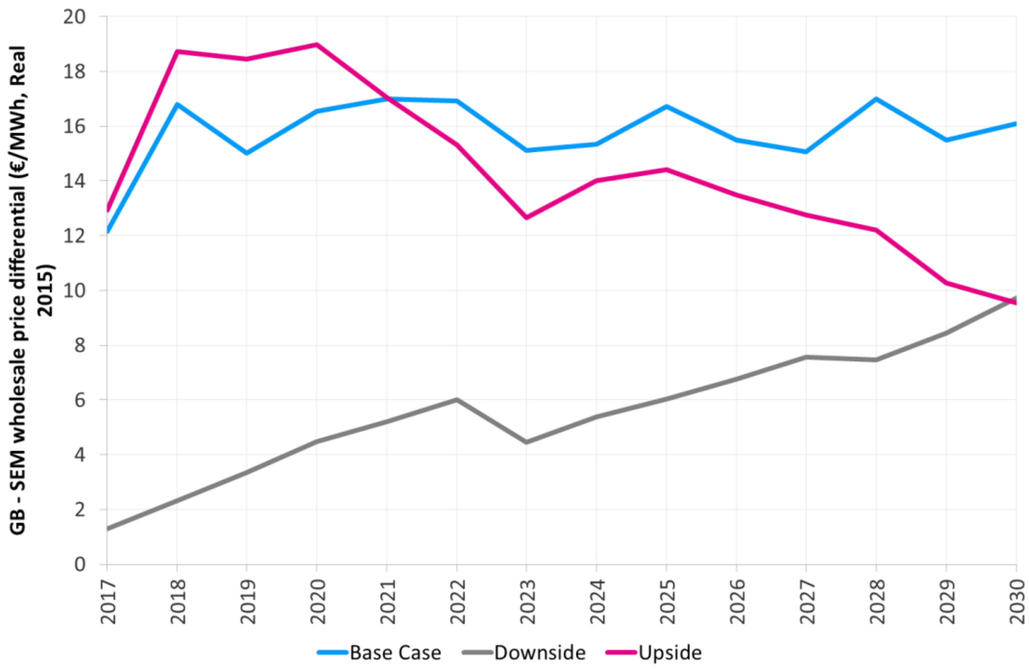
Reference and sensitivities

		EWIC capacity	Moyle capacity (MW)	Base Case	Upside	Downside
Quadratic/Linear loss functions including fixed component	Reference ramp rates 5 MW/min	500 - 530 MW	287/295 – 410/450 80 – 410/450 from 10/11/2017	✓	✓	✓
Quadratic/Linear loss functions excluding fixed component	Reference ramp rates 5 MW/min	500 - 530 MW	287/295 – 410/450 80 – 410/450 from 10/11/2017	✓		
No Losses	Reference ramp rates 5 MW/min	500 - 530 MW	287/295 – 410/450 80 – 410/450 from 10/11/2017	✓		
Linear loss function Including fixed losses at full load	Reference ramp rates 5 MW/min	500 - 530 MW	287/295 – 410/450 80 – 410/450 from 10/11/2017	✓		
Quadratic/Linear loss functions including fixed component	No ramp rates	500 - 530 MW	287/295 – 410/450 80 – 410/450 from 10/11/2017	✓		
Quadratic/Linear loss functions including fixed component	Reference ramp rates 5 MW/min	500 - 530 MW	287/295 – 410/450	✓		
Quadratic/Linear loss functions including fixed component	Reference ramp rates 5 MW/min	500 - 530 MW	287/295 – 410/450 500 – 410/450 from 01/01/2023	✓		

Results

Power price differential

GB - I-SEM Wholesale power price differential (€/MWh, Real 2015)



- In all scenarios, we project higher prices in GB than in I-SEM
- The key reasons are as follows:

1. In the Base and Upside scenarios, GB Carbon Price Support is maintained: this initially adds around €8-9/MWh to GB prices, other things being equal, though the effect gradually declines over the timeframe as coal plant in GB are closed and the EU ETS price rises
2. The GB price is on an 'NBP basis', meaning that balancing and use of system costs incurred by generators are included in the GB wholesale price. This adds around €3/MWh to the GB price, other things being equal. The analogous costs in the Irish market are socialised
3. GB has a tighter capacity margin than SEM and I-SEM throughout the timeframe (circa 5% in GB and 10-15% in I-SEM). The GB margin is particularly tight due to the closure of coal and older gas capacity under the IED. This in turn means that scarcity premia are higher in the GB market
4. The Celtic interconnector is assumed to commission in the early 2020s and relatively low French wholesale prices put downward pressure on prices in I-SEM
5. I-SEM has a relatively high proportion of wind generation compared to the GB market. This has the broad effect of pushing gas capacity to the right in the merit order and in some periods I-SEM prices are set by wind. This effect is magnified by the assumption that Moyle's export capacity is limited to 80MW

- There is an offsetting effect associated with Irish gas transportation charges. The variable component is added to I-SEM SRMCs but we assume the capacity component is recovered in the I-SEM CRM. Overall the impact of these charges is smaller than the combined impact of the factors listed above, leading to the systematic positive delta between GB and I-SEM prices

Results

Gross Margin

Gross Margin (Million €)

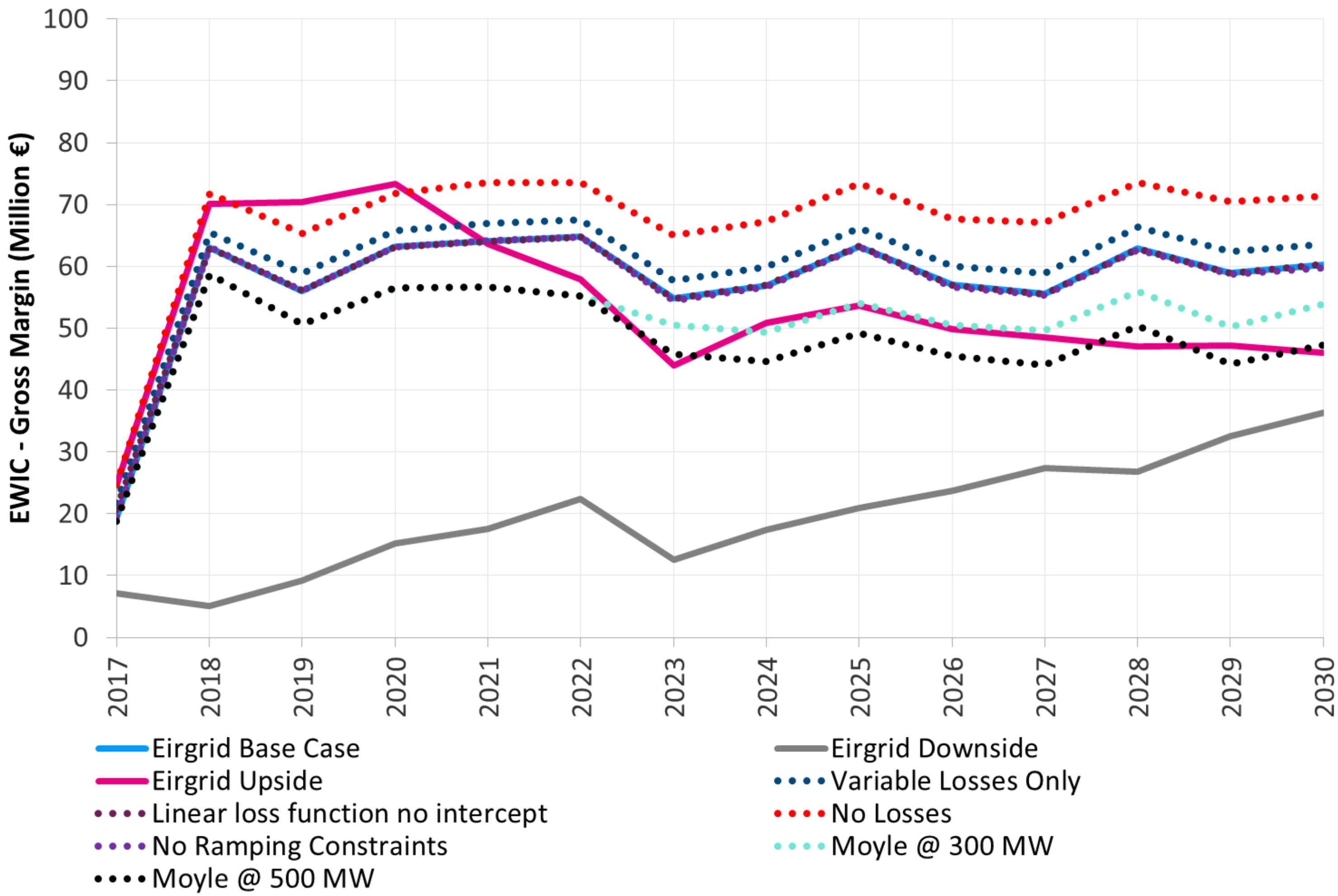
EWIC	2017	2018	2019	2020	2021
Reference	19.5	63.1	56.1	63.2	64.1
Downside	7.1	5.0	9.2	15.1	17.5
Upside	24.8	70.1	70.3	73.3	63.7
Variable losses only	21.8	65.5	58.8	65.8	66.9
No losses	24.7	71.7	65.4	71.8	73.6
No ramping	19.5	63.1	56.1	63.2	64.1
Moyle @ 300	18.8	58.7	50.6	56.6	56.7
Simple loss function	20.8	63.0	56.1	63.1	64.1
No losses and no ramping	24.7	71.7	65.4	71.8	73.6

- The gross margin rises significantly when I-SEM is introduced and energy flows are no longer (we assume) influenced by the capacity payment mechanism
- The Downside case has much lower revenues due to the absence of Carbon Price Support and price uplift in GB: these are the main two factors that affect future interconnector profitability
- Under the 'no losses' sensitivity, annual gross margins for EWIC are €5-9m higher than in the Reference Case
- Ramping is found to make only a small difference to gross margins due to predominantly one-way direction of energy flow
- Higher capacity on Moyle (300MW instead of 80MW) reduces gross margins by circa €5-7m per annum

Results

EWIC Gross Margins

Gross Margin (Million €)



Results

Exports

Exports (GWh)

EWIC	2017	2018	2019	2020	2021
Reference	1568	4146	4049	3951	3878
Downside	821	1902	2267	2324	2205
Upside	1634	4090	3989	3838	3571
Variable losses only	1628	4156	4061	3963	3891
No losses	1774	4197	4143	4088	4034
No ramping	1580	4142	4043	3939	3863
Moyle @ 300	1566	4113	4000	3880	3787
Simple loss function	1478	4153	4053	3950	3872
No losses and no ramping	1714	4194	4136	4078	4015

Results

Imports

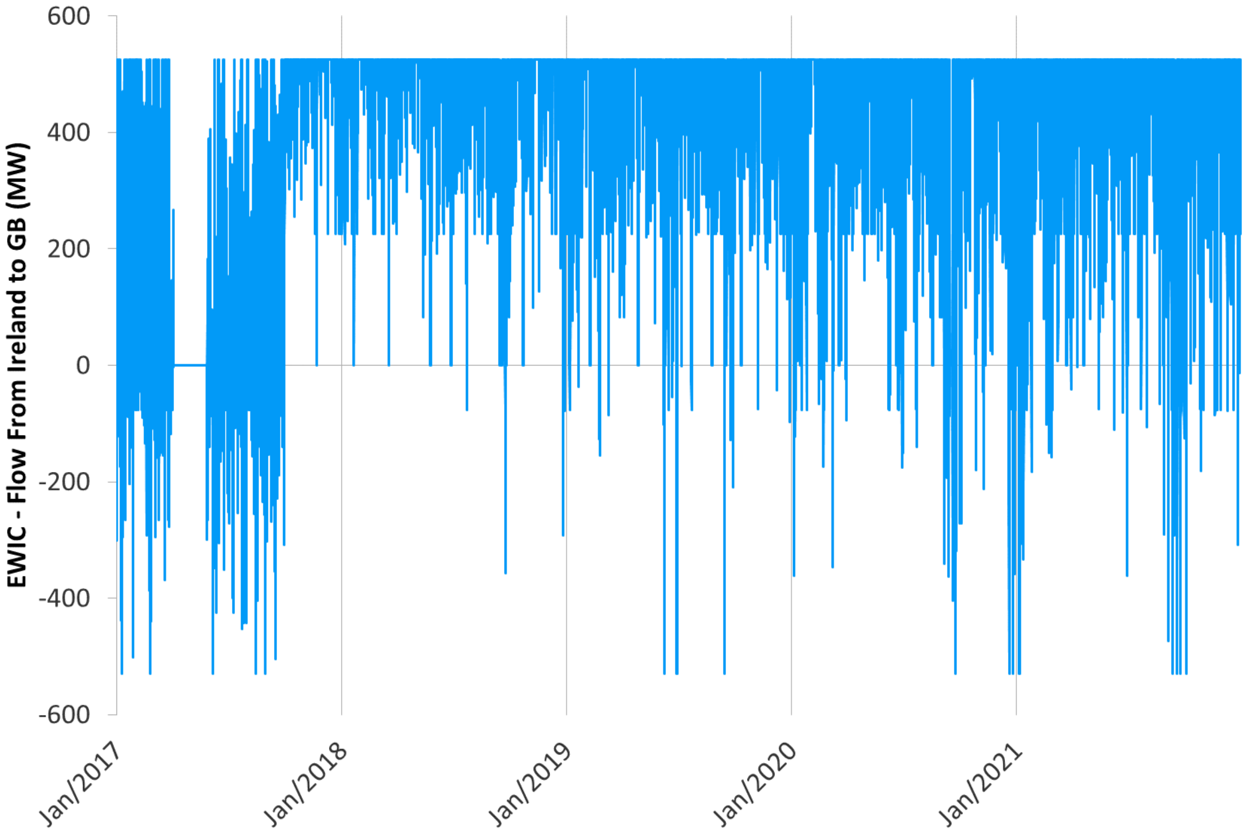
Imports (GWh)

EWIC	2017	2018	2019	2020	2021
Reference	170	2	18	21	24
Downside	1159	228	137	163	161
Upside	187	1	10	18	54
Variable losses only	142	2	18	21	24
No losses	205	2	23	22	31
No ramping	155	3	20	29	33
Moyle @ 300	170	2	19	23	26
Simple loss function	47	1	16	17	17
No losses and no ramping	206	5	28	38	56

Results

EWIC - Hourly Flow

EWIC - Hourly Flow from Ireland to GB (MW, Reference Case)

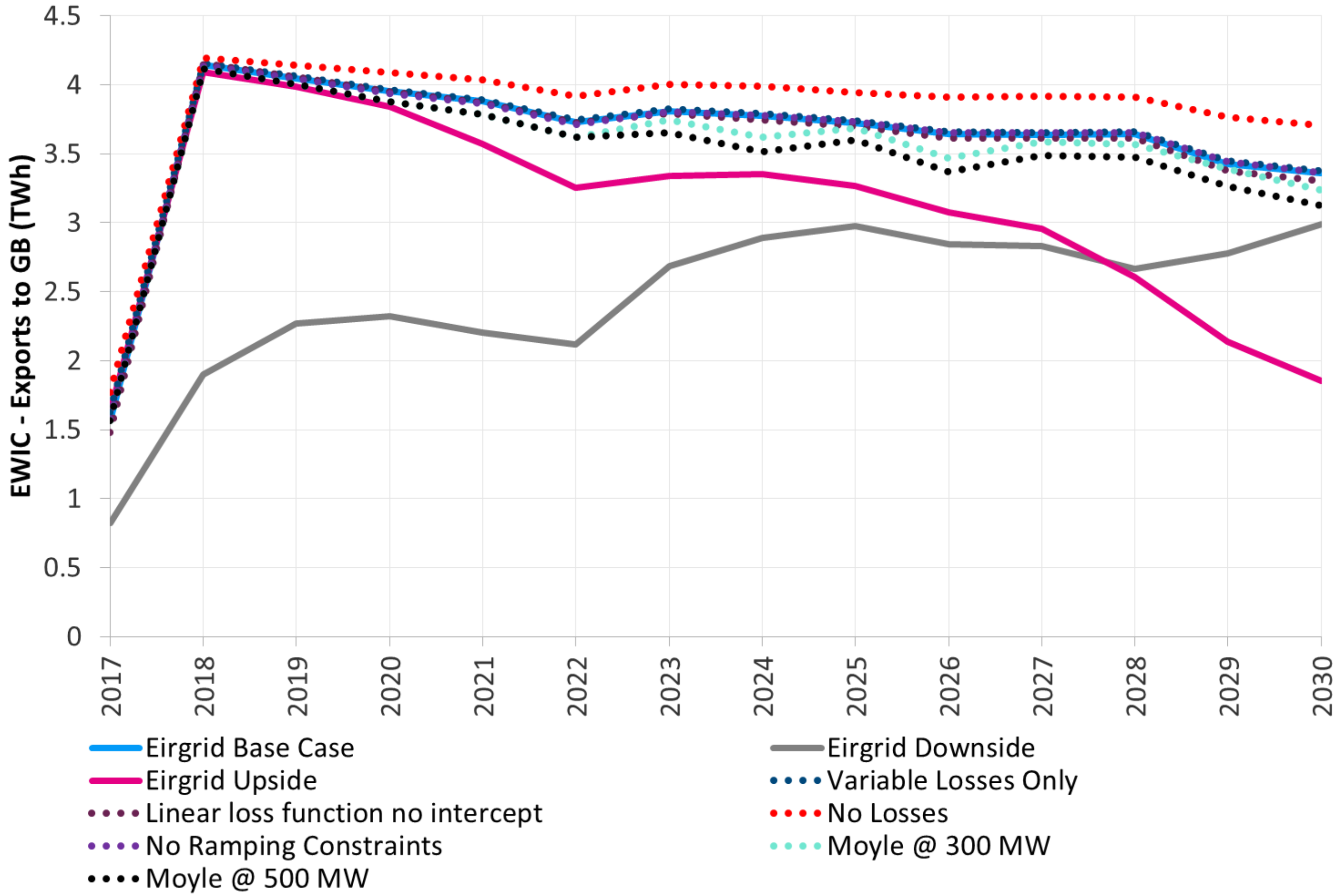


- Energy flow is predominantly from Ireland to GB in our analysis due to the systematic positive price delta (GB>I-SEM) observed for the factors on slide 24
- The Capacity Payment Mechanism counteracts these factors in some hours during 2017 before it is replaced by the I-SEM mechanism in Q4

Results

EWIC exports to GB

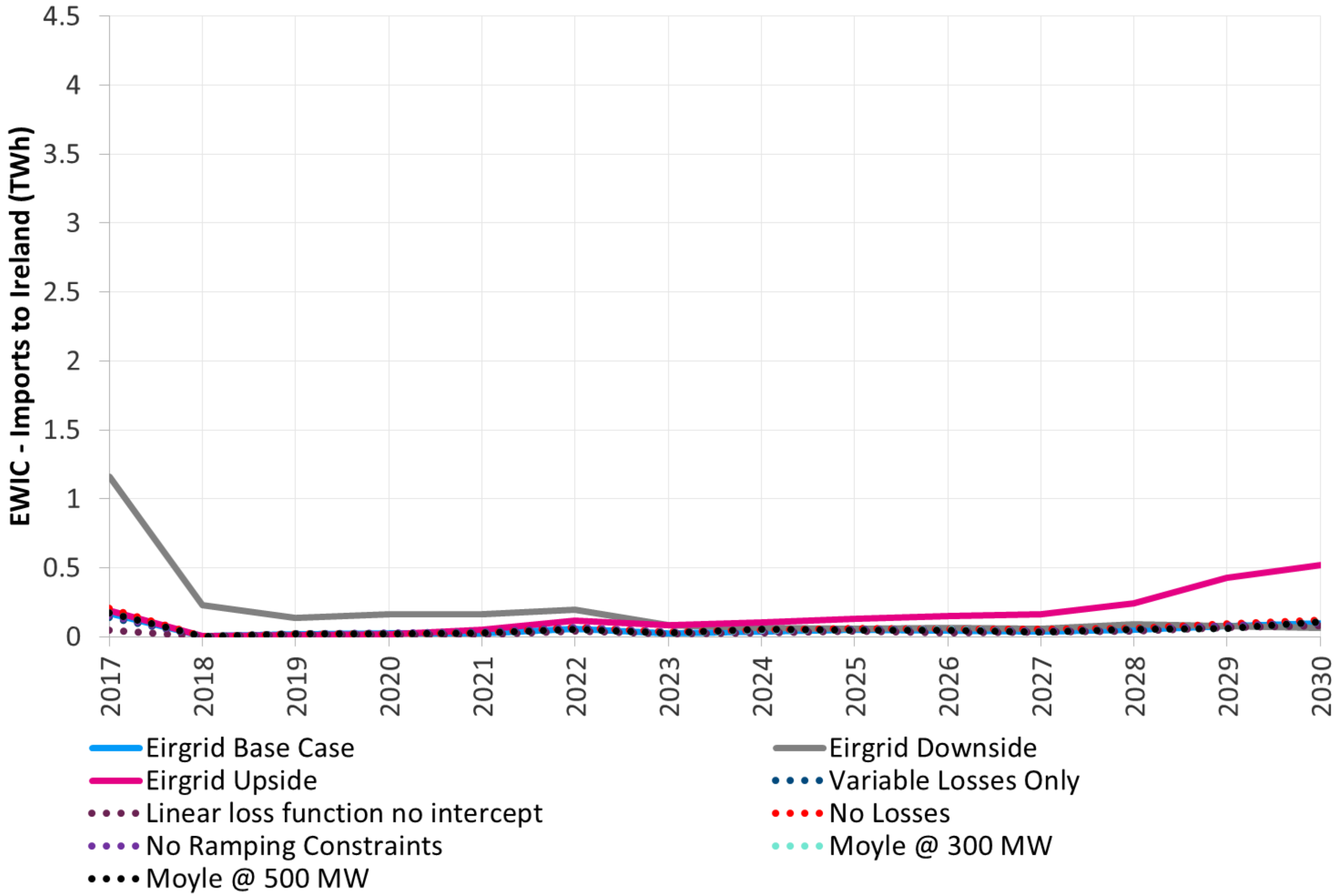
Exports to GB (TWh)



Results

EWIC imports to Ireland

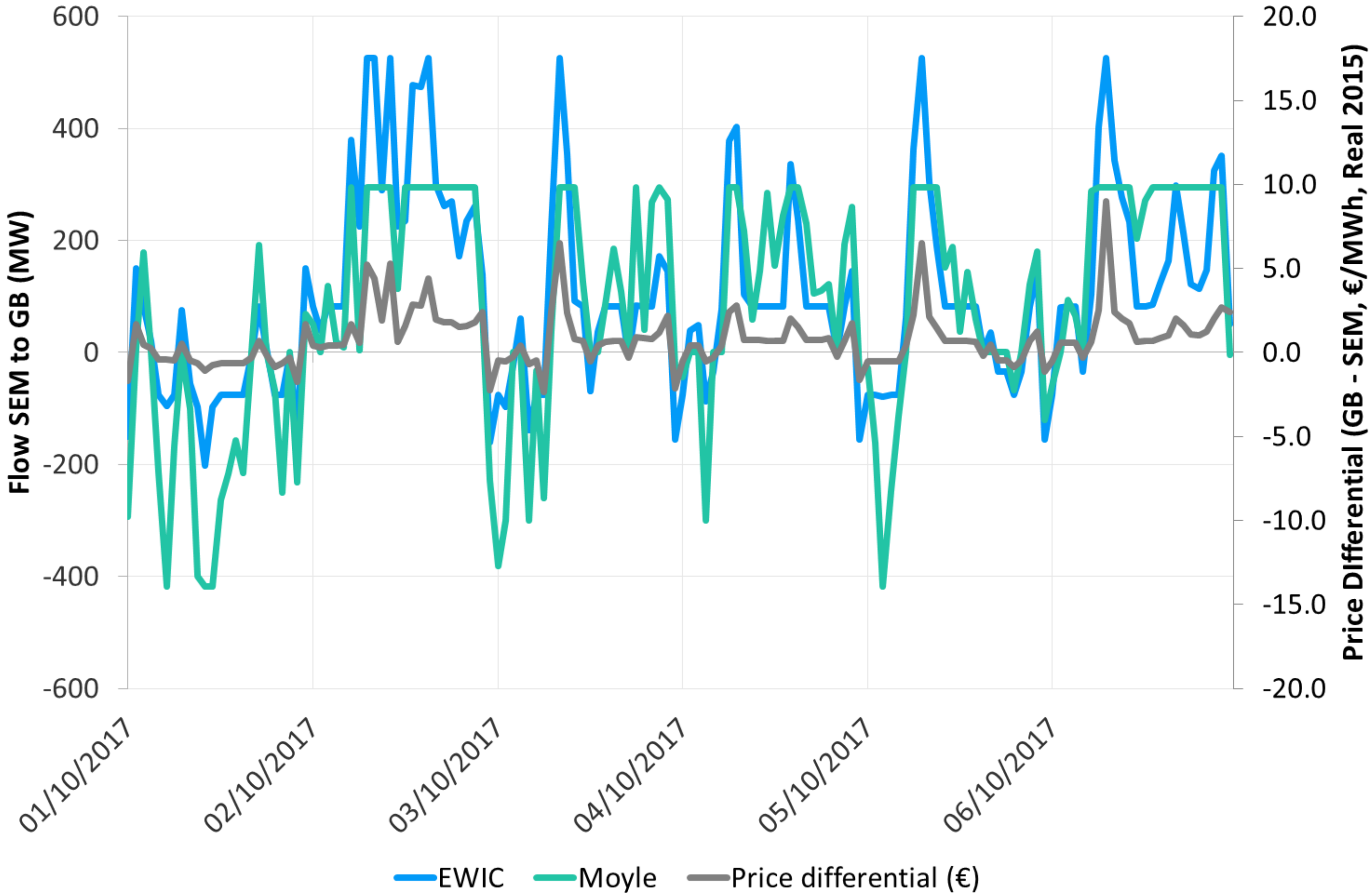
Imports to Ireland (TWh)



Results

Example of hourly flows

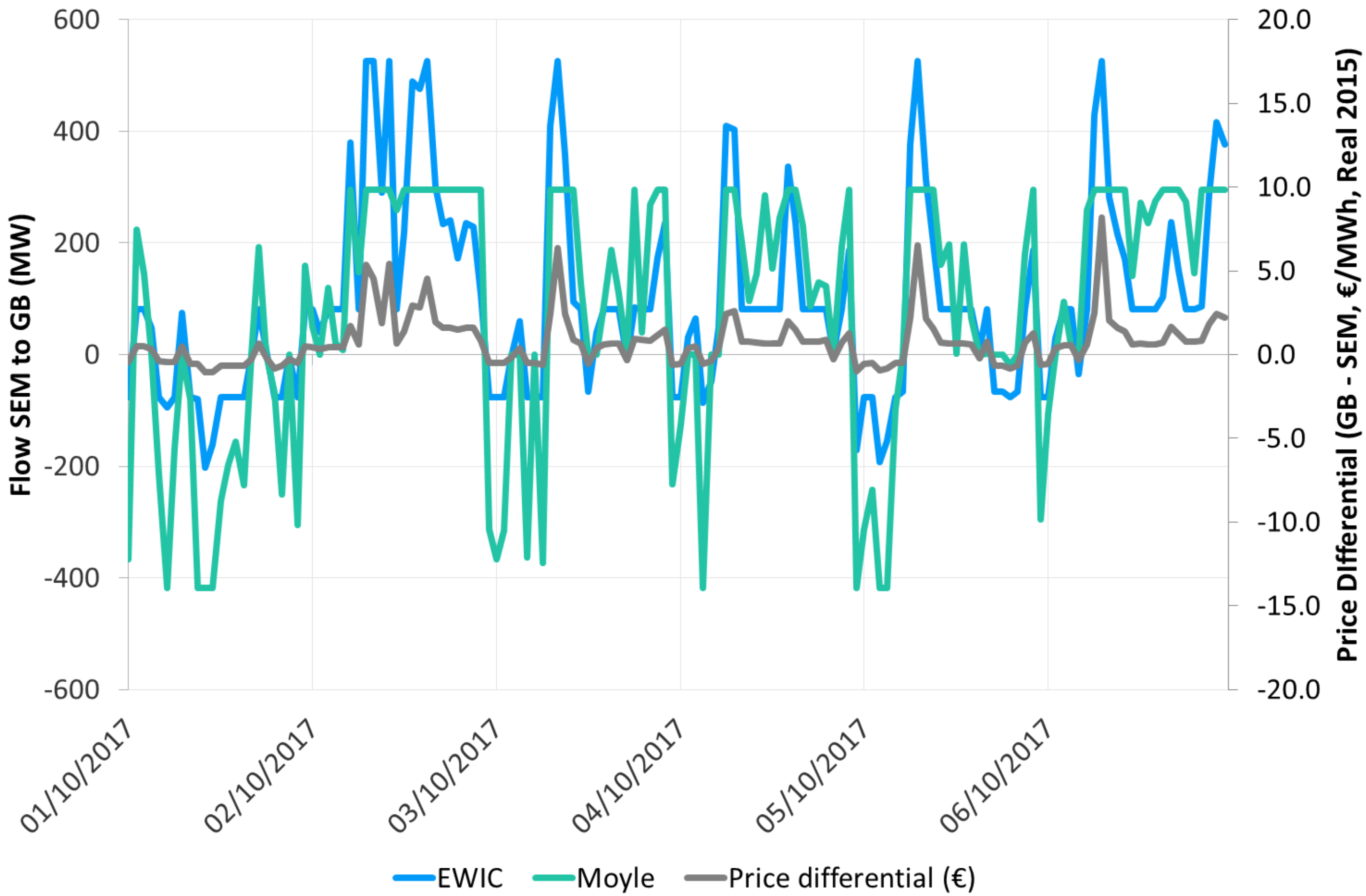
Example of hourly flows (Downside case)



Results

Impact of ramping constraints on flows

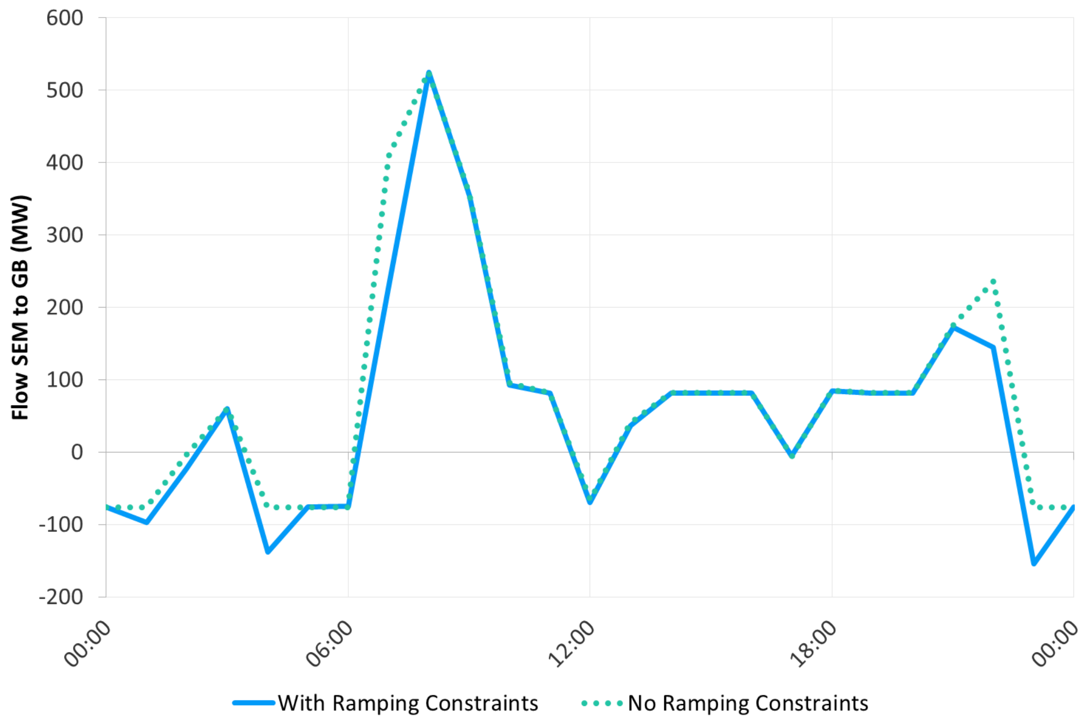
The impact of removing ramping constraints on flows (Downside case)



Results

The cost of ramping constraints

EWIC Flow - (Downside case, 3rd October 2017)



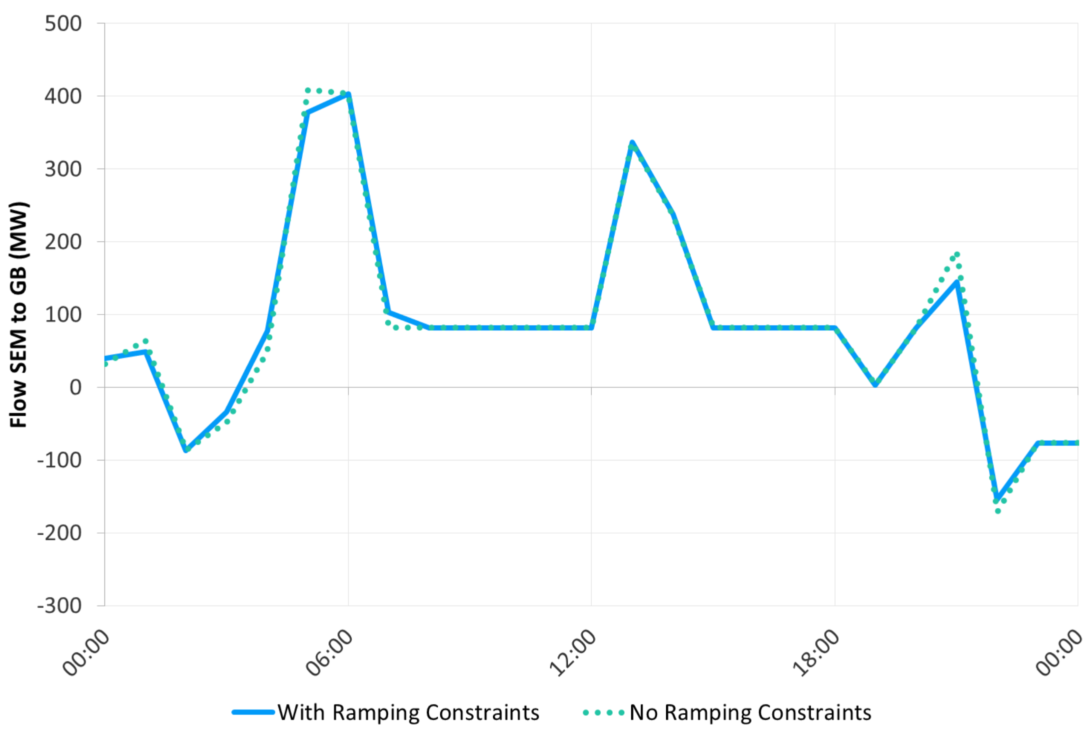
The cost of ramping constraints

- We estimate that the cost of ramping and part loading for the day shown in this example (3rd October 2017) is €8,821 of which €6,554 is due to part loading and €2,267 is due to ramping

Results

The cost of ramping constraints

EWIC Flow - (Downside case, 4th October 2017)



The cost of ramping constraints

- We estimate that the cost of ramping and part loading for the day shown in this example (4th October 2017) is €7,724 of which €7,237 is due to part loading and €487 is due to ramping

Contents

Methodology for assessment of FTRs

Quantitative analysis using PLEXOS results

- EWIC and Moyle will earn revenues from congestion rents but will also incur liabilities from the sale of Financial Transmission Rights (FTRs). These liabilities in theory will be offset by FTR auction revenues, but the interconnectors (and TUOS customers) are exposed to the extent the offset is not a perfect match. Baringa has not analysed auction revenues. We have estimated the FTR liabilities under various assumptions and compared them with the congestion rents. In the following slides, the liabilities are referred to as "FTR pay-out" and the difference between rents and FTR pay-out is referred to as "gross margin exposure due to FTR"
- The exposure is broken down into three elements:
  - Cost of ramping
  - Cost of part loading
  - Cost of losses
- The sum of these elements is the total exposure associated with an FTR that assumes there are no ramping constraints, no part loading and zero losses. If the FTR is adjusted for one or more or these elements, the exposure is correspondingly reduced
- We have included, under 'part loading', costs that can occur from energy flows against the spread; these arise in particular in SEM due to the influence of the Capacity Payments Mechanism
- We have also quantified negative cashflows that can arise from FTR Obligations. We assume the Obligations imply baseload flow in the direction SEM to GB and determine the most negative daily cashflows in each year of each scenario for each interconnector. These negative cashflows are based on market price differences unadjusted for losses
- **We have used this analysis to address the first three questions raised by the SEM Committee in the FTR Consultation Paper of 8 September**

Results

Impact of FTR design on Gross margins (Reference)

Impact of FTR – Reference Case

EWIC		2017 SEM	2017 I-SEM	2018	2019	2020	2021
Gross Margin	*Million €*	3.8	17.4	63.1	56.1	63.2	64.1
FTR option payout	*Million €*		20.3	74.5	67.7	74.8	76.0
Gross margin exposure due to FTR	*Million €*		-2.9	-11.4	-11.6	-11.6	-11.9
Cost of ramping	*Million €*		0.0	0.1	0.1	0.2	0.2
Cost of part loading	*Million €*		0.0	0.2	0.4	0.6	0.7
Part loading %	*%*	74%	6%	9%	15%	19%	22%
Cost of losses	*Million €*		2.8	11.1	11.1	10.8	11.0
Cost of losses with a linear function (No intercept)	*Million €*		2.9	11.2	11.2	10.9	11.1
Max daily FTR obligation exposure	€		-	-	25,381	29,253	-

- We have included, under ‘part loading’, costs that can occur from flows against the spread
- Cost of losses reflect both the loss factor and the volume of energy transported
- The maximum daily FTR obligation exposure is calculated as follows. We assume that capacity in the direction I-SEM to GB is sold with the volume equalling EWIC’s capacity. No capacity is sold in the opposite direction. The FTR holder receives payments if the GB price is higher but pays out if the I-SEM price is higher. Over a day, the aggregate is usually positive but might be negative. The table above shows the highest negative value (i.e. the largest daily payment that the holders have to pay in each year). In Q4 2017, 2018 and 2021 the value is zero (i.e. there is never a day when the holders have to pay out).

Results

FTR Valuation (Reference)

Reference case

FTR Contract, Notional Value 1 MW		2017	2018	2019	2020	2021
FTR Obligation (Receive GB price minus SEM price)	€	39,204	147,184	131,469	145,261	148,835
FTR Obligation (Receive SEM price minus GB price)	€	-39,204	-147,184	-131,469	-145,261	-148,835
FTR Option (Receive GB price minus SEM price where positive)	€	39,208	147,285	131,863	145,810	149,497
FTR Option (Receive SEM price minus GB price where positive)	€	5	101	394	549	662

FTR Contract, Notional Value EWIC max capacity net of outages		2017	2018	2019	2020	2021
FTR Obligation (Receive GB price minus SEM price)	*Million €*	20.3	74.4	67.3	74.2	75.5
FTR Obligation (Receive SEM price minus GB price)	*Million €*	-20.3	-74.4	-67.3	-74.2	-75.5
FTR Option (Receive GB price minus SEM price where positive)	*Million €*	20.3	74.4	67.5	74.5	75.7
FTR Option (Receive SEM price minus GB price where positive)	*Million €*	0.0	0.1	0.2	0.3	0.3

- The FTR Obligation is valued assuming baseload flow in one direction. The FTR Option is valued assuming flow, in one direction, only if the price spread in that direction is positive. The FTR Option values in the two directions sum to equal the FTR Option payout shown on the previous slide.

Results

Impact of FTR design on Gross margins (Downside)

Impact of FTR – Downside case

EWIC		2017 SEM	2017 I-SEM	2018	2019	2020	2021
Gross Margin	*Million €*	12.7	1.2	5.0	9.1	15.1	17.5
FTR option payout	*Million €*		3.1	12.1	16.4	22.2	24.3
Gross margin exposure due to FTR	*Million €*		-2.0	-7.1	-7.3	-7.0	-6.8
Cost of ramping	*Million €*		0.1	0.3	0.3	0.3	0.4
Cost of part loading	*Million €*		0.5	2.1	2.0	1.9	1.9
Part loading %	*%*	61%	78%	80%	75%	71%	73%
Cost of losses	*Million €*		1.3	4.7	5.1	4.9	4.5
Max daily FTR obligation exposure	€		3,715	39,004	43,545	64,202	23,103

- In the Downside Case, smaller price spreads lead to a greater incidence of part loading and a greater associated value. This is particularly true for EWIC given its higher loss factor (utilisation is lower and there are more 'starts and stops' of flow compared with Moyle)
- FTR Obligation exposure is relatively high compared to the Reference Case given a greater number of periods when the I-SEM price is higher than the GB price.

Results

FTR Valuation - Downside

Downside case

FTR Contract, Notional Value 1 MW		2017	2018	2019	2020	2021
FTR Obligation (Receive GB price minus SEM price)	€	5,272	20,465	29,266	39,398	45,528
FTR Obligation (Receive SEM price minus GB price)	€	-5,272	-20,465	-29,266	-39,398	-45,528
FTR Option (Receive GB price minus SEM price where positive)	€	5,755	22,963	30,985	41,328	47,508
FTR Option (Receive SEM price minus GB price where positive)	€	482	2,497	1,719	1,930	1,980

FTR Contract, Notional Value EWIC max capacity net of outages		2017	2018	2019	2020	2021
FTR Obligation (Receive GB price minus SEM price)	*Million €*	2.7	9.7	14.8	20.3	22.3
FTR Obligation (Receive SEM price minus GB price)	*Million €*	-2.7	-9.7	-14.8	-20.3	-22.3
FTR Option (Receive GB price minus SEM price where positive)	*Million €*	2.9	10.9	15.6	21.2	23.3
FTR Option (Receive SEM price minus GB price where positive)	*Million €*	0.2	1.2	0.8	0.9	1.0

- The FTR Obligation is valued assuming baseload flow in one direction. The FTR Option is valued assuming flow, in one direction, only if the price spread in that direction is positive. The FTR Option values in the two directions sum to equal the FTR Option payout shown on the previous slide.

Results

Impact of FTR design on Gross margins (Upside)

Impact of FTR – Upside case

EWIC - Margins and FTR option exposure		2017 SEM	2017 I-SEM	2018	2019	2020	2021
Gross Margin	*Million €*	7.9	18.8	70.1	70.3	73.3	63.6
FTR option payout	*Million €*		22.0	82.4	82.9	85.9	76.7
Gross margin accouting for FTR exposure	*Million €*		-3.2	-12.3	-12.6	-12.6	-13.0
Cost of ramping and part loading	*Million €*		0.1	0.5	0.8	1.2	1.8
Part loading %	*%*	73%	7%	13%	19%	26%	36%
Cost of losses	*Million €*		3.1	11.8	11.8	11.4	11.3
Max daily FTR exposure			-	-	-	59,432	567

- In the Upside Case, flows are largely in the eastwards direction (as in the Reference Case); this reflects the significant gap between GB and I-SEM prices caused by Carbon Price Support and higher scarcity uplift in the GB market
- Hence, part-loading and ramping costs are relatively low although they become more significant in later years

Results

FTR Valuation - Upside

Upside case

FTR Contract, Notional Value 1 MW		2017	2018	2019	2020	2021
FTR Obligation (Receive GB price minus SEM price)	€	42,549	163,995	161,599	166,717	149,229
FTR Obligation (Receive SEM price minus GB price)	€	-42,549	-163,995	-161,599	-166,717	-149,229
FTR Option (Receive GB price minus SEM price where positive)	€	42,567	164,105	161,914	167,327	150,697
FTR Option (Receive SEM price minus GB price where positive)	€	18	110	316	610	1,468

FTR Contract, Notional Value EWIC max capacity net of outages		2017	2018	2019	2020	2021
FTR Obligation (Receive GB price minus SEM price)	*Million €*	22.0	82.3	82.6	85.3	75.4
FTR Obligation (Receive SEM price minus GB price)	*Million €*	-22.0	-82.3	-82.6	-85.3	-75.4
FTR Option (Receive GB price minus SEM price where positive)	*Million €*	22.0	82.3	82.8	85.6	76.0
FTR Option (Receive SEM price minus GB price where positive)	*Million €*	0.0	0.1	0.2	0.3	0.7

- The FTR Obligation is valued assuming baseload flow in one direction. The FTR Option is valued assuming flow, in one direction, only if the price spread in that direction is positive. The FTR Option values in the two directions sum to equal the FTR Option pay-out shown on the previous slide.

Consultation document: Q1

Are FTR Obligations or FTR Options to be preferred?

Quantitative Analysis

- **We have not attempted to model auction prices within this scope of work; these prices will be influenced by participant behaviour, trading positions, company structure and strategy, and credit requirements amongst other factors**
- **We have calculated the 'fair value' of the Option and Obligation in each year based on EWIC's capacity (circa €70m per annum during I-SEM in the eastwards direction in our Reference Case but as low as €12m in our Downside Case in 2018)**
- We have also quantified the risk to holders of Obligations that arises from negative pay-outs, as shown on the preceding slides
- This analysis indicates that the 'worst day' could see a cost to the FTR holder of circa €50-60k
- We have not taken a view on collateral requirements; the analysis could be easily repeated for different timescales

Consultation document: Q1

Are FTR Obligations or FTR Options to be preferred?

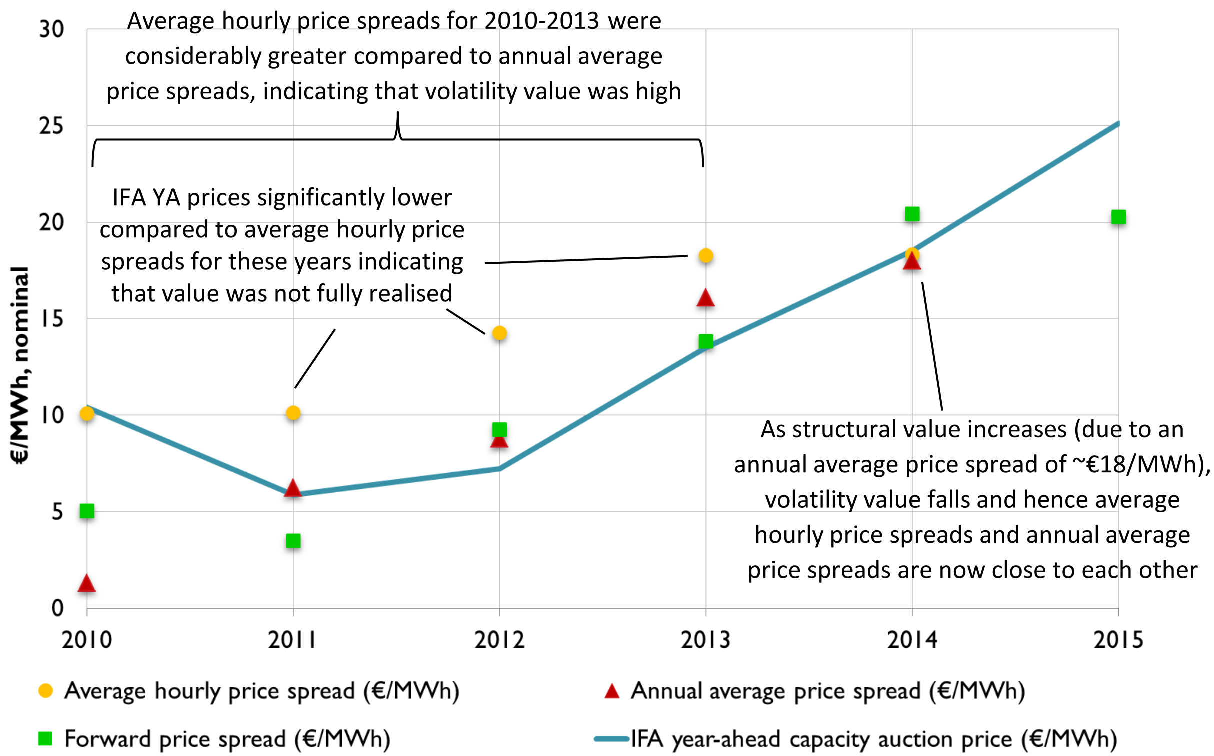
Qualitative Assessment

- **On balance, we believe FTR Options are to be preferred. We do not repeat the pros and cons listed in the consultation document. However, we emphasize the following points:**
  - First, current physical products in SEM are more like FTR options and are typically used by SEM suppliers to hedge/source their peak demand. Today's auction bidders in the GB-to-SEM direction are likely to price based on their peak requirements.
  - Historically, other interconnectors (e.g. IFA) have also used physical products which are more like FTR options. Hence, experience in SEM and across Europe is of options not obligations.
  - Buyers of obligations may be risk-averse and over-discount in bidding for FTRs due to the open-ended exposure to reverse payments. This risk aversion is likely to be comprised of a) the need to provide collateral to cover credit risk and b) lack of experience and familiarity with obligations.
  - Netting, a theoretical advantage of Obligations, is unlikely to be significant given that a) the optimal direction of flow is likely to be predictable, once the year-ahead stage has been reached, and b) there is likely to be broad market consensus of this. It is possible that players with opposite positions (long in I-SEM and short in GB on the one hand, and short in I-SEM and long in GB on the other) will have incentives to flow in opposite directions due to transaction costs, but these are likely to be relatively minor compared with market price differences.
  - Options are in theory harder to value, because the value depends on the detailed shape of prices, whereas for Obligations the fair value depends on average prices (ignoring losses). History suggests that auction participants usually price on the basis of expected average price differentials (see next slide). This is a consideration in favour of Obligations, particularly if average prices are close together but there is significant uncorrelated price volatility in the two markets. However, in this world the risk from adverse flows under Obligations is also increased.
  - If there is a stable 1-way delta between market prices, the theoretical fair values of Options and Obligations converge, but we judge Options to be favourable for the reasons of risk-aversion and lack of familiarity with Obligations mentioned above.

Historical GB-FR spreads and IFA YA capacity auction prices

History on IFA suggests that auction participants tend to bid close to average price differences and discount the option value associated with hourly price differences

Average hourly price spread, Annual average price spread, Forward price spread, IFA Year-Ahead capacity auction price (nominal €)



- **Average hourly price spread** is calculated by first considering the hourly differences (in absolute terms) between the French and GB prices over a year, and then taking the average of those differences over that year
- **Annual average price spread** is calculated by first taking the annual average of the hourly French prices and the hourly GB prices, and then considering the difference between the two
- **Forward price spread** is calculated by considering the difference between the French and GB prices using a range of different forward products for a given year (MA+0, MA+1, MA+2, QA+0, QA+1, SA+0, SA+1)
- **IFA year-ahead capacity auction price** is the sum of the auction clearing prices for both directions. Only IFA calendar year YA products are included in this graph (financial year YA products are also available)

Key message:

- Interconnector revenues are based on hourly price spreads and these are typically greater compared to annual average price differentials between the connected markets

Consultation document: Q2

Is it better to have 1 FTR or an FTR for each interconnector?

Quantitative Analysis

- **We have analysed the FTR exposure that would arise from assuming the FTR makes no allowance for losses, ramping or part-loading**
  - This would be the situation, we understand, if 1 FTR were to be employed for both links
- In our Reference Case, the exposure is €12m per annum on average for 2018-2021 for EWIC
- The exposure is similar in our Upside scenario and somewhat less in our Downside scenario
- We estimate that the costs associated with part loading will be significantly reduced under I-SEM and the risks associated with a single FTR are then largely related to the cost of losses

Consultation document: Q3

Should FTRs be net of ramping, losses or part-loading?

Quantitative Analysis

- **We have separated out the individual components; in our Reference Case they are as follows:**
  - The cost associated with ramping is relatively small, around €0.1m per annum following the introduction of I-SEM
  - Losses are the most significant element; the cost is circa €11m per annum during 2018-2021 for EWIC
  - The cost of part loading is relatively small, less than €1m per annum for EWIC following the introduction of I-SEM. Although the number of periods in which part loading occurs may be substantial, the amount of part loading is only significant when the price differential between GB and I-SEM is small and hence the financial cost is relatively small
- We agree with the 'minded to' position of the SEM Committee that FTRs should be adjusted for losses
- We have not quantified the issue of curtailment. Our analysis has assumed that when the links experience forced outages, the associated revenues are zero and the FTRs operate 'back-to-back' in this respect

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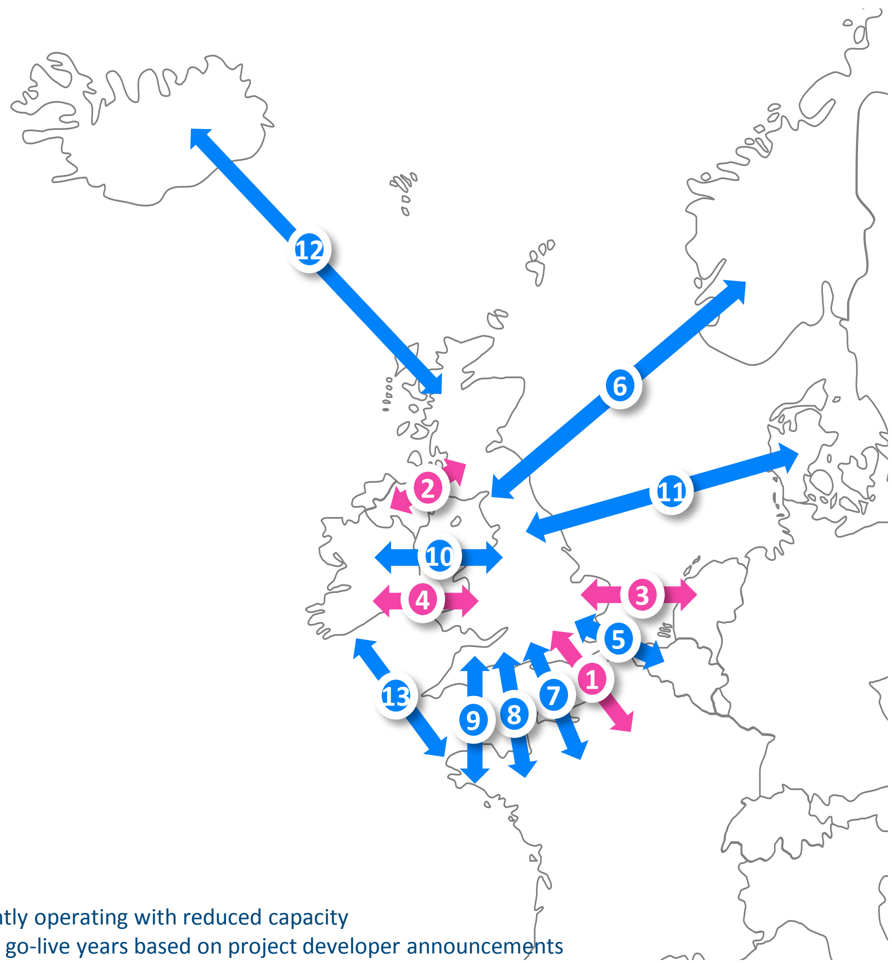
Interconnector projects

Interconnectors projects



¹ Currently operating with reduced capacity
² Target go-live years based on project developer announcements
*Commissioned in 2021 in the upside scenario

Baringa Reference Case assumptions

	Country	Capacity (MW)	Status	Target²	Baringa Ref Case
1	IFA	2000	Existing	1986	1986
2	Moyle	450¹	Existing	2001	2001
3	BritNed	1000	Existing	2012	2012
4	East West	500	Existing	2012	2012
5	Nemo	1000	Proposed	2018	2019
6	NSN	1400	Proposed	2020	2021
7	IFA 2 /FABLink	1000	Proposed	2020	2022
8	ElecLink	1000	Building	2017	2018
9	IFA 2 /FABLink	1400	Proposed	2020	-*
10	GreenLink	500	Proposed	2025	-
11	Viking	1000	Proposed	2020	-
12	ICELink	1000	Proposed	2027	-
13	Celtic	700	Proposed	2023	2023

Capacity assumptions

GB - Base Case

GB Capacity mix (GW)

- All scenarios assume new plant coming on-line as required to ensure required levels of security of supply
- Coal plant in GB close in line with EU policy, with renewables, gas and nuclear forming the majority of new build

	2015	2016	2017	2018	2019	2020	2021
CCGT	28.2	29.0	29.0	31.6	31.4	29.9	26.5
Coal	18.5	14.6	14.5	12.3	11.3	9.3	9.3
Nuclear	9.1	8.6	8.6	8.6	8.6	8.6	8.6
Onshore Wind	8.2	8.9	9.6	10.2	10.9	11.5	11.5
Offshore Wind	4.2	4.9	5.9	7.1	8.2	9.8	10.1
Solar	8.0	10.0	10.5	11.0	11.5	12.0	12.4

- National Grid Slow Progression:

	2015	2016	2017	2018	2019	2020	2021
CCGT	25.8	26.4	27.7	29.0	30.0	29.5	30.0
Coal	17.8	14.9	14.9	12.5	9.9	9.9	8.0
Nuclear	9.0	9.0	9.0	9.0	9.0	8.0	8.0
Onshore Wind	8.2	9.1	10.5	11.3	12.0	12.4	12.7
Offshore Wind	5.0	5.0	5.2	7.0	7.7	8.6	9.7
Solar	6.0	7.4	8.7	9.9	10.9	11.8	12.4

Capacity assumptions

GB - Upside

GB Capacity mix (GW)

- Baringa projections assuming strong growth in low carbon technologies, with a particular focus on offshore wind and solar

	2015	2016	2017	2018	2019	2020	2021
CCGT	28.2	29.0	29.0	31.6	31.4	31.8	29.9
Coal	18.5	14.6	14.5	14.2	12.3	9.3	9.3
Nuclear	9.1	8.6	8.6	8.6	8.6	8.6	8.6
Onshore Wind	8.2	8.9	9.7	10.5	11.2	12.0	12.2
Offshore Wind	4.2	4.9	5.9	7.1	8.2	9.8	10.4
Solar	8.0	10.0	10.5	11.0	11.5	12.0	12.9

- National Grid Consumer Power:

	2015	2016	2017	2018	2019	2020	2021
CCGT	25.8	26.6	28.7	30.4	29.3	29.5	32.0
Coal	17.8	16.0	14.9	11.5	10.4	9.4	8.0
Nuclear	9.0	9.0	9.0	9.0	9.0	9.0	9.0
Onshore Wind	8.3	9.4	10.8	11.8	12.4	13.0	13.4
Offshore Wind	5.0	5.1	6.2	7.1	8.1	9.3	9.3
Solar	7.0	9.4	11.7	14.0	16.1	18.0	19.4

Capacity assumptions

GB - Downside

GB Capacity mix (GW)

- Baringa projections assuming low growth in low carbon technologies due to poor macro conditions

	2015	2016	2017	2018	2019	2020	2021
CCGT	28.2	29.0	29.0	31.6	31.4	31.4	30.7
Coal	18.5	14.6	14.5	12.3	9.8	9.8	7.9
Nuclear	9.1	8.6	8.6	8.6	6.3	6.3	6.3
Onshore Wind	8.2	8.9	9.7	10.5	11.2	12.0	12.0
Offshore Wind	4.2	4.9	5.9	7.1	8.2	9.8	9.8
Solar	8.0	10.0	10.5	11.0	11.5	12.0	12.0

- National Grid No Progression

	2015	2016	2017	2018	2019	2020	2021
CCGT	26.8	26.6	28.6	30.1	31.4	30.9	34.2
Coal	17.8	14.9	14.9	12.9	10.4	10.4	6.5
Nuclear	9.0	9.0	9.0	9.0	9.0	9.0	9.0
Onshore Wind	8.0	8.9	10.1	10.8	11.0	11.3	11.5
Offshore Wind	5.0	5.0	5.2	6.5	7.2	8.1	9.3
Solar	5.7	6.6	7.4	7.9	8.3	8.6	9.0

Capacity assumptions

Ireland – Base case

Ireland Capacity mix (GW)

- All scenarios assume new plant coming on-line as required to ensure required levels of security of supply
- Existing thermal plant close in line with EU policy, with renewables and gas forming the majority of new build

	2015	2016	2017	2018	2019	2020	2021
CCGT	5.8	5.7	5.7	5.7	5.3	5.3	5.3
OCGT	0.7	0.7	0.7	0.7	0.7	0.7	0.7
Coal	1.3	1.3	1.3	1.3	1.3	1.1	0.9
Peat	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Hydro & PS	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Wind	2.8	3.1	3.4	3.6	3.9	4.2	4.5

- EirGrid Generation Capacity Statement 2015-2024

	2015	2016	2017	2018	2019	2020	2021
CCGT	5.3	5.7	5.4	5.4	5.5	5.3	5.3
OCGT	0.7	0.8	0.8	0.8	0.8	0.8	0.8
Coal	1.3	1.3	1.3	1.3	1.3	1.3	1.3
Peat	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Hydro & PS	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Wind	2.8	3.3	3.7	4.3	4.5	4.7	4.8

Capacity assumptions

Ireland

Ireland Capacity mix (GW)

- Upside case - Baringa projections assuming strong growth in wind

	2015	2016	2017	2018	2019	2020	2021
CCGT	5.8	5.7	5.7	5.7	5.3	5.3	5.3
OCGT	0.7	0.7	0.7	0.7	0.7	0.7	0.7
Coal	1.3	1.3	1.3	1.3	1.3	1.1	0.9
Peat	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Hydro & PS	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Wind	2.8	3.3	3.7	4.3	4.5	4.7	4.8

- Downside case - Baringa projections assuming low growth in wind

	2015	2016	2017	2018	2019	2020	2021
CCGT	5.8	5.7	5.7	5.7	5.3	5.3	5.3
OCGT	0.7	0.7	0.7	0.7	0.7	0.7	0.7
Coal	1.3	1.3	1.3	1.3	1.3	1.1	0.9
Peat	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Hydro & PS	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Wind	2.8	3.1	3.3	3.5	3.7	4.0	4.2