Email to: RO@energysecurity.gov.uk

9 October 2023

To whom it may concern,

Consultation Response: Call for Evidence on introducing Fixed Price Certificates into the UK-wide Renewables Obligation schemes

Scottish Renewables is the voice of Scotland's renewable energy industry. Our vision is for Scotland leading the world in renewable energy. We work to grow Scotland's renewable energy sector and sustain its position at the forefront of the global clean energy industry. We represent over 330 organisations that deliver investment, jobs, social benefits and reduce the carbon emissions which cause climate change.

Our members work across all renewable energy technologies, in Scotland, the UK, Europe and around the world. In representing them, we aim to lead and inform the debate on how the growth of renewable energy can help sustainably heat and power Scotland's homes and businesses.

As the UK's largest renewable electricity support scheme, the Renewables Obligation (RO) has played a critical role in incentivising the deployment of renewables and contributing to the government's net-zero agenda. It is therefore of critical importance that the RO scheme continues to provide stable, reliable support for RO generators, both to maintain the viability of RO assets and uphold investor confidence in the UK market.

Scottish Renewables recognises the importance of ensuring that the RO scheme does not have an outsized impact on consumer bills. However, it should also be recognised that the UK's longstanding grandfathering principles play a critical role in facilitating access to low-cost financing for renewables projects, both now and in the future. Attempting to reduce consumer bills by making retrospective changes to legacy renewables support schemes would introduce new policy risks to the UK market, as well as threaten the viability of assets still in receipt of legacy policy support. To make retrospective changes to the RO scheme would therefore be a shortsighted policy decision which would have severe consequences for the cost, pace and scale of the UK's future deployment of renewable energy.

Some of the proposals contained within this call for evidence, namely the removal of the 10% headroom for the buyout price of a Fixed Price Certificate (FPC) and the proposed changes to indexation, represent such retrospective changes. This call for evidence has therefore caused serious concern across industry. We believe this call for evidence also has significant procedural flaws which undermine its ability to gather insight and data from stakeholders on how the market is operating to inform next steps and further consultation on potential policy.

It does not ask stakeholders for information on market dynamics, nor does it ask stakeholders to test any hypothesis or strawman examples of the proposed changes. Much of the rationale since a move to FPCs was signalled in 2011 has changed, as acknowledged in the call for evidence. In the interim there has been little guidance to market participants on how to prepare for any transition and many PPAs have been signed that are operational well into the 2030s. We believe these concerns must therefore be addressed and resolved before any further steps towards transitioning to a FPC model are taken.

Scottish Renewables welcomes the opportunity to respond to this call for evidence and has provided full responses to the call for evidence questions in the attached appendix. However, in responding, we would like to highlight the following points:

- **Scottish Renewables is strongly opposed to the proposals to remove the 10% headroom from the buy-out price of a fixed price ROC, to move from RPI to CPI for indexation and to remove compounded year-on-year inflation.** These proposals represent retrospective changes to the RO scheme which, if implemented, would alter the basis on which significant investments were made. They would contravene previously published government commitments in 2011 and Ofgem RO guidance in 2019 which created legitimate expectations across industry that have informed views on future cash flows and hence asset values. The changes proposed in the call for evidence would therefore **severely undermine investor confidence in the UK as well as the well-earned stability and policy certainty of GB energy regulation more widely**. This would have a significant impact on consumers as a high level of predictability is required for companies to deploy low-cost capital at scale in long-dated renewables projects. These proposals create further unease across industry at a time of increasing uncertainty for generators given recent developments such as the introduction of the Electricity Generator Levy (EGL), the failure of CfD Allocation Round 5 to procure any offshore wind, and the prolonged consideration of Locational Marginal Pricing (LMP) and the investment risks presented by its potential implementation. This context must be taken into account as **damaging investor confidence risks increasing the cost of capital potentially making the net zero transition costlier to deliver.**
- Scottish Renewables recognises that there may indeed be a case for a move to a FPC model and we fully welcome and appreciate the underlying motivation to protect generators and investors from depressed ROC revenues towards the end of the scheme. However, we are concerned that the case for transitioning to a FPC model has not been examined in sufficient detail. We therefore believe that there should be a rigorous cost-benefit analysis of a move to a FPC model. The call for evidence only sets out the rationale for a move to a FPC model at a high level, with no quantification of the relative benefits and disbenefits. Before any policy change of this magnitude is

undertaken, it needs to be demonstrated conclusively that there is a net benefit to doing so.

- Should it be decided that a move to a FPC model will proceed, there needs to be a thorough appraisal of the most appropriate date to make the transition. The government acknowledges that price volatility in the RO scheme is not expected to emerge until the 2030s, but it proposes maintaining the 2027 date for making the transition because of other supposed (unquantified) benefits. We believe there needs to be further analysis of when exactly price volatility will emerge as this will impact the case for when the transition should occur. We also believe that the government may be underestimating some of the costs of making the transition. For example, PPAs will typically not have the 2027 transition date written into them as the government suggests, but rather change of law clauses. This means that every such PPA will need to be rewritten and repriced upon a move to a FPC model. The transitional costs mean that we believe there could be an argument for delaying the move to a FPC model until the 2030s to align with when price volatility is expected to emerge. Retaining the 2027 transition date may in fact result in significant costs whilst not capturing the benefits from managing price volatility, at least not in the initial years after the transition. In any case, the government needs to take care to identify when price volatility will develop and accurately evaluate transition costs (as well as the overall cost-benefit case) before deciding on the most suitable date to transition to a FPC model.
- With significant market reform already being undertaken, the priority for government must remain forward-looking programmes like the Review of Electricity Market Arrangements (REMA) rather than changes to legacy schemes. There must also be a recognition that there is limited capacity within industry to engage with and manage changes to market arrangements. It must be ensured that implementing any changes to the RO scheme does not delay implementing the reforms critical to reaching net-zero.

Scottish Renewables would be keen to engage further with this agenda and would be happy to discuss our response in more detail.

Yours sincerely,

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Appendix: Answers to call for evidence questions

Model 1 – Central counterparty, no trading in certificates

Q1. What are the benefits and drawbacks associated with Model 1?

Benefits:

- This model would provide greater revenue certainty as well as reducing the administrative burden and costs for both generators and suppliers due to its relative simplicity.
- Having a central counterparty also reduces the excess expenditure associated with third parties in the current ROC system.
- This model could also be beneficial for business resourcing as it could mitigate the need to track a complicated buy-out/mutualisation fund which would also help to reduce financing risk premiums.

Drawbacks:

- This model represents a greater departure from the current system and therefore could involve a more costly and administratively burdensome transition.
- This model could also have negative implications for cash flow and the overall flexibility of market participants. This would be exacerbated if the less frequent settlement options are carried forward. Therefore, if monthly settlement is not feasible, for example, if suppliers are unable to match a monthly frequency, there may be benefits to retaining trading of certificates.
- The feasibility of monthly payments will depend on the ability of suppliers to gather levy payments from customers to match this schedule. This needs to be determined through the call for evidence process.
- Model 1 will most likely require a full-scale negotiation of all PPAs that include ROCs. In addition, it will require suppliers to pay for the ROCs/FPCs earlier and/or it will necessitate the creation of a bridging fund, which may be costly.

Q2. On balance, which option for frequency of payment and settlements do you think strikes the best balance of benefits for all market participants and why?

From a generator's perspective, monthly settlement is preferred. However, quarterly settlement could represent the best balance for all market participants.

If monthly settlements are not feasible, trading in certificates could potentially mitigate cash flow concerns and enable greater flexibility.

Q3. For your preferred option, which measures are most important to minimise the risks associated with this option?

Retrospective recovery has the advantage of being simpler as well as reducing forecasting risk.

A retrospective annual obligation for suppliers increases the risk of suppliers misusing customer credit balances as working capital and could expose the market to a repeat of mutualisation events due to the non-payment of the RO in recent years by some suppliers. Ofgem will require suppliers to ringfence their obligation attributed to domestic electricity supply, which mitigates this risk.

Advanced settlement may also be smoother to implement as a simple reserve fund can be used rather than more complex bridging loans.

Q4. What would the impact of each option be on scheme administration, including costs?

No comment.

Q5. What broad impact would Model 1 have over the sector? We welcome evidence specifically on cost of capital, risk premiums, and administrative costs to relevant market participants.

No comment.

Model 2 – Central counterparty, trading in certificates

Q6. What are the benefits and drawbacks associated with Model 2?

Benefits:

- Model 2 is closer to the current system which may therefore be less disruptive to market participants when transitioning from the current scheme. It may therefore also reduce the burden of rewriting and renegotiating PPAs when change of law clauses are triggered.
- Trading may also reduce the costs for the central buyer which in turn reduces costs to the consumer.
- The ability to trade certificates may enable more flexibility for generators to manage cashflow and could provide the option for earlier payments. A large proportion of ROCs are sold at a discount to the buy-out price in PPA arrangements and retaining trading would continue to enable this flexible approach. If monthly settlements are not

possible, some generators therefore see potential benefits from having the option of trading.

Drawbacks:

- The incentives to trade under a fixed price scheme are significantly reduced. In the absence of a market or supplier obligation to drive market trading the value of this model may be greatly reduced.
- The complexity of Model 2 may increase the administrative and financial costs for market participants, which could in turn increase the costs to the consumer. These costs may outweigh the benefits in terms of flexibility and of reducing the disruption to the PPA market.

Q7. On balance, which option for frequency of payments and settlements do you think strikes the best balance of benefits for all market participants, and why?

If trading in certificates is chosen, the settlement periods should be as frequent as possible. Options that include annual settlement should be discounted.

Q8. For your preferred option, which measures are most important to minimise the risks associated with this option?

No comment.

Q9. What would the impact of each option be on scheme administration, including costs?

No comment.

Q10. What broad impact would Model 2 have over the sector? We welcome evidence specifically on cost of capital, risk premiums, and administrative costs to relevant market participants.

No comment.

Q11. Of the two models presented in this document, which would you favour, and why?

Scottish Renewables does not feel able to offer a firm preference for either model without further information about how they would operate and a quantitative analysis of their likely impact.

Themes

Q12. What are the respective benefits and drawbacks of having advanced payment by suppliers and reconciliation? On balance, do you consider that the benefits outweigh the drawbacks?

We believe that LCCC could be best placed to be the billing agency.

Advance payments require more granular forecasting and are associated with a risk of misalignment, which increases with longer settlements, and the need for a reconciliation mechanism. Advanced payments also increase uncertainty for suppliers which will be factored into pricing which is ultimately a cost to the consumer. We therefore favour retrospective settlement options as they would be easier to administer.

However, advanced payments have the advantage of ensuring Ofgem has earlier warnings of potential supplier issues and non-payment. The efficacy of advanced payment is therefore sensitive to the conditions of the supplier market, which must be assessed and modelled before any changes are considered.

Q13. What are the benefits and risks of adding headroom to the supplier obligation to manage any potential discrepancy between the forecasted supplier obligation and actual generator receipts?

We favour establishing a reserve fund over adding headroom to the supplier obligation. Adding headroom to the supplier obligation would likely cost consumers more than establishing a reserve fund. A reserve fund with a credit facility similar to that used by the LCCC in the Contracts for Difference scheme could be appropriate.

Q14. How should the surplus headroom be redistributed, and why?

As stated above, Scottish Renewables favours establishing a reserve fund rather than adding headroom to the supplier obligation.

Q15. What benefits and drawbacks would a reserve fund have as compared to a headroom?

Headroom should be provided to generators at the full amount as expected in previous policy guidance and Ofgem documents.

Establishing a reserve fund would mean that consumers pay, and generators are paid, the correct amount and it deals with the cashflow mismatch efficiently.

Q16. Besides headroom and a reserve fund, are there other options for dealing with the risk of misalignment under advanced settlement options?

No comment.

Q17. What risks might this option present for suppliers, consumers, or the central counterparty?

For suppliers and consumers, establishing a bridging reserve carries fewer risks than a reconciliation mechanism. As the call for evidence states, if calculated accurately, the bridging reserve would only require funds to be topped up by suppliers on one occasion and, with sufficient notice, would be much easier for suppliers to manage via an advance levy.

Q18. What information regarding the introduction of the new schedule will suppliers require and by when to set consumer tariffs and manage PPA arrangements appropriately?

No comment.

Q19. What are the potential benefits and drawbacks of centralising both functions of administrator and central counterparty into a same entity?

Another option would be to use the LCCC as it already has the systems in place to manage much of the transition.

Pricing

Q20. What factors should be taken into account when setting the price of FPCs?

Investor Confidence in UK Policy Stability

One of the most important factors to be taken into account when setting the price of FPCs is the legitimate expectation of that price by existing investors in RO-supported projects.

The level of policy stability in a country is a significant factor in an investor’s assessment of the level of risk for making investments in that country. The level of risk in turn affects the required rates of return on investment and the corresponding cost of the capital needed to fund those investments.

A key concern is that the section on “Pricing” in the call for evidence only mentions “investor interests” very briefly and does not consider investor confidence and its wider policy implications. This factor needs to be fully assessed and quantified for the reasons set out below.

The RO is a closed support scheme, with a series of commitments made by the UK government on its future intentions for the scheme, through to its final closure. Investors in RO projects relied on those commitments when making decisions prior to the closure of the scheme and subsequently. All investors will treat the stability (or otherwise) of the RO scheme arrangements as a key indicator of the level of policy risk in the UK.

To date, grandfathering of existing RO projects has been a key feature of RO throughout its duration, which has provided reassurance and certainty to investors. That has carried through to their assessments of other UK projects, for example those supported by the CfD, when assessing the policy and regulation risk for energy investments in the UK.

The importance of maintaining investor confidence has the following consequences for setting the price of the FPC: -

- The price should be set at a level that matches the legitimate expectations of investors, or there will be a significant adverse impact on the confidence of all investors in the UK energy system.
- The effect of that adverse impact on investor confidence will extend far beyond the existing RO projects, to affect all future investment decisions in UK electricity generation projects.
- Investors in RO projects will be directly impacted, with a reduction in revenues and investments than they projected. They will increase their risk rating for future UK projects in response.
- However, non-RO investors will also increase their risk rating as well, to manage the risk of future losses from unexpected changes in policy.
- The consequence will be an increase in the cost of capital for investments in all future renewable generation projects, which will increase the cost to UK electricity customers of delivering low carbon generation to deliver net zero.

The increases in investment costs could be substantial and of a similar order of magnitude to the costs of the existing RO.

Cost to the Consumer

The cost to the consumer is another important factor to be considered when setting the price for FPCs. However, as explained above, the potential impacts on cost to the consumer extend far beyond the headline price of the FPC. If retrospective changes to the FPC are applied, this will impact investor confidence and increase the cost to the consumer of future generation projects. These wider consequences for cost to the consumer need to be taken into account, as well as the headline cost of the FPC itself.

Q21. Should the price of FPCs be set at a level which excludes the ten per cent headroom built into the current scheme? Why and why not? As caveated above, please treat these questions as only applying to scenarios where the chosen FPC model does not involve the use of a new headroom designed to manage misalignment between the supplier obligation settlements levied and the payments issuing to generators.

Scottish Renewables is strongly opposed to the proposal to remove the 10% headroom from the buy-out price of FPCs.

The Government made a clear, unequivocal commitment in 2011 to retain the 10% headroom upon a move to a FPC model. As stated in paragraph 203 in Annex C of this DECC policy update: "*Our intention is for the price of the Fixed ROC to be set at the long term value of the ROC. In 2027, this will be the 2027 buyout price, plus 10 per cent. The Fixed ROC price would remain inflation-linked from 2027, in the same way that the buyout price is currently inflation linked."* This was clearly presented to provide confidence to investors in the long-term value of the ROC after 2027, as evidenced by related wording in paragraph 192 which stated: *"We are aware that investors and developers taking long term investment decisions would like more detail on how the Fixed ROC scheme will operate from 2027-37. Therefore, the aim of this update is to provide further detail of our proposals."*

This followed similarly worded commitments in Annex D of the 2011 'Planning Our Electric Future' white paper: -

- "The Government supports the principle of no retrospective change for renewables investments, and through the consultation process have listened to industry views on the best way to transition to the Feed-in Tariff with Contract for Difference (FiT CfD). With these vintaging arrangements, we recognise the importance of maintaining industry confidence and stable conditions for investment decisions made on the basis of RO support." (D.5)
- "The arrangements for transition are based on the principles of transparency, longevity and certainty. This Annex sets out in full how the RO will operate to 2037. The arrangements are subject to statutory consultation requirements set out in section 32L of the Electricity Act 1989, and Parliamentary and EU State Aid approval." (D.6)
- "We will set the value of the fixed ROC now, to give certainty for investors, at the long-term value of a ROC which is the buyout price plus 10 per cent headroom (roughly £41 per ROC at current prices)." (D.63)

Developers were investing into the RO scheme up until 2015 and even beyond as transitional arrangements allowed, and these investment decisions were based on the 2011 assurance that the 10% headroom would be maintained. To break this commitment would therefore be a retrospective change to the RO scheme which would severely damage investor confidence at a time when it is already fragile during what is a critical decade for renewable energy delivery. An adverse change to the FPC would add to these impacts, at a time when the EU and USA are taking active steps to positively encourage investment in new renewables.

Recent energy policy developments such as the introduction of the Electricity Generator Levy and the failure of CfD Allocation Round 5 to secure any offshore wind have already adversely impacted investor confidence. Even if the removal of the 10% headroom isn't implemented, this proposal is already adversely impacting investors' views on the UK as an attractive investment opportunity.

One reason put forward in the call for evidence for removing the 10% headroom is that this will reduce the cost to the consumer. This in turn is put forward as a reason to introduce the FPC in 2027, rather than wait until the early 2030s. However, a political risk premium will be added to future investments because of the retrospective change to an established policy. This will diminish any consumer benefit of removing the 10% headroom. Any consumer benefit would be further offset by the additional charges that suppliers will need to apply to manage the generation volume risk that they will need to manage under the FPC. In addition, there will also be ongoing costs of administration for the counterparty and administrator, which will ultimately be passed to the consumer.

Another argument in favour of removing the 10% headroom set out in the call for evidence is that wholesale prices have increased. This is a weak argument. The ROC is designed so we take the risk on the wholesale power element if it is lower (as it has been) or higher (as has also occurred). A short-term change in the wholesale market should not lead to a large change in the commercial risk and reward of the ROC regime.

Q22. Should the price of FPCs be indexed to the CPI instead of the RPI (as under the current scheme)?

The price of FPCs should be indexed to RPI as under the current scheme as arrangements upon which investments were made must be grandfathered in any move to a FPC model. To move to CPI would represent a retrospective change to the scheme with severe consequences for investor confidence as set out above. If the government nevertheless decides to proceed with moving to CPI for indexation, in order to mitigate the impact on investor confidence we suggest that RPI is replicated by using, for example, CPI plus one percentage point.

Q23. What would be the implications for generators of a shift to CPI? How much of an impact would this have on the viability of continuous operation of RO plants?

As the OBR records for RPI and CPI demonstrate, RPI has typically been 1.0% higher than CPI in recent years. The consequence of indexing to the CPI would therefore be a progressive reduction in the FPC price, compared to the value that an investor would have expected under RPI.

As the UK Government has not previously suggested making any change to the index for the RO, investors have had a legitimate expectation that the FPC price would increase in line with the RPI. A change to CPI would be a retrospective policy change. It would create a significant impact on investor confidence, with the consequences that we have set out in our answer to Question 21. Even if it isn’t implemented, this proposal, in combination with the proposal to remove 10% headroom from the FPC price, is already adversely impacting investors’ views on the UK as an investment opportunity. The impact on investor confidence and the associated costs is not addressed in the call for evidence and should be fully reviewed and quantified.

Q24. What are the benefits and drawbacks associated with Option 1 and Option 2 of this section? Which option would you favour?

Scottish Renewables believes the existing indexation methodology should be retained; we are strongly opposed to the removal of compounded year-on-year inflation and to the introduction of either of these two options. The effect of either option would be to reduce the out-turn level of indexation of the FPC to a level below the legitimate expectation of investors (which is based on the cumulative application of RPI). To change the indexation methodology would represent yet another retrospective change to the scheme, with the consequences which we have set out in response to Q.21.

High inflation rates are likely to be a short-term issue and we do not consider the proposed options as being proportionate actions in response to recently observed inflation rates.

Moreover, neither of the proposed options would accurately replicate inflation. Either option would single out generators that are supported by the RO for the application of a unique approach to indexation for inflation that has not been applied to any other policy mechanism or category of generator. Whilst we recognise and understand the underlying motivation driving these proposals, namely, to ensure the right balance of costs for consumers, to implement either proposal would be inconsistent, arbitrary and a poor approach to policy making. If implemented, either would set ominous precedents which would create new risks for other policy mechanisms.

Timing

Q25. Do you agree with the proposal to introduce the new FPC model in 2027?

Scottish Renewables believes thorough analysis is required to identify the most suitable date to make a transition to a FPC model.

The cost and administrative burden of renegotiating PPAs could be considerable if the transition to a FPC model proceeds in 2027 and the government has previously indicated that it understands the importance of limiting the impact on the PPA market. This was demonstrated in the 2014 Government Response to the consultations on the Renewables Obligation Transition and on Grace Periods which stated, *"In the July 2011 White Paper, the Government confirmed that we would address this issue by calculating the RO annually by headroom until 31 March 2027, and then moving to a Fixed Price Certificate (FPC) Scheme, with the price of certificates fixed at the 2027 buyout price, plus 10%. This approach was designed to balance the need to protect parties to Power Purchase Agreements (PPA) and financing agreements from the impact of triggering change in law provision, against the need to give long-term certainty over ROC income and ensure RO stability in the final years of the scheme."*

With the potential for significant transitional costs and the fact that price volatility is not expected to emerge until the 2030s, there may be a case for delaying the transition until this point. Depending on the result of a full cost-benefit analysis of a move to a FPC model there might not be a case for making the transition at all.

It is important that a fully quantified cost-benefit analysis is carried out to inform the decision on the appropriate date to introduce a new FPC model. Preliminary analysis by some within SR membership has indicated that: -

- There are no benefits from a move to FPC in 2027, rather than the early 2030s. The risk of ROC price volatility does not arise until the early 2030s. Other potential benefits are not relevant or can be delivered in other ways. This includes the rebalancing of costs from electricity to gas bills.
- However, there are substantial costs for generators, suppliers and consumers from a move to FPC in 2027, both transitional and ongoing. Transitional costs include: -
    - Renegotiation of PPAs by generators and consumers
    - Renegotiation of land leases by generators
    - Ongoing costs include:
    - The cost to suppliers (which would then be passed on to consumers) of managing RO generation volume risk. The proposed move to FPCs

introduces a levy mechanism that means suppliers ultimately pay their RO supplier charges based on actual ROC generation. This will introduce a significant new risk to suppliers due to the uncertainty of ROC generation levels.
    - A risk to generators from the move to an FPC arises from the fact that, for a year with a low total volume of renewable generation (and corresponding low total number of ROCs), there will no longer be an increase in ROC recycle value from the reduced ROC volumes.
- These costs can be avoided or substantially reduced by waiting until the early 2030s to move to FPC.
- As there is a net cost to consumers from a move to FPC in 2027, it is not appropriate to proceed at that time and the move should be deferred.
- There may be a case for a move to FPC in the early 2030s, but this requires a full quantification to be carried out of all costs and benefits.
- The reasons why costs are reduced by waiting until the early 2030s to move to FPC include:
    - The total number of PPAs and leases needing to be amended will reduce each year as generators progressively leave the RO. As a result, the total cost of the FPC transition can be minimised by deferring the move to the FPC as long as possible.
    - Suppliers will need to charge customers to manage their new risk of significant losses in a year with high RO generation levels. It will be an ongoing cost, so will apply continually from the time of the move to the FPC. This cost to the consumer can be minimised by deferring the move to the FPC as long as possible.

In addition, policy aims directed at reducing the risk of supplier default and mutualisation are likely already addressed through recent Ofgem decisions to require suppliers to 'ring-fence' their obligation attributed to domestic supply and revisions of the mutualisation threshold.

Government should also be careful to bear in mind that industry has limited capacity to deal with changes to policies and market arrangements. Making changes to legacy schemes will take valuable time and resource away from more important policy changes, such as REMA.

How RO reform interacts with other ongoing reforms to the electricity market, including REMA, reform of the retail market and grid charges, is another important factor which needs to be considered in the timing of a move to a FPC model.

Q26. What length of time would constitute a reasonable period of notice for market participants and other parties (e.g. administrator, counterparty) to prepare for the transition to the new model?

Most market participants will require at least one full compliance year after a move to a FPC model is legislated to prepare for the transition. There would also need to be a comprehensive roadmap and guidance published by government to support this transition.

However, suppliers typically allow customers to fix forward supply contracts for up to 4 years into the future. Suppliers would therefore benefit from having 4 years notice of the transition. We therefore recommend that the maximum notice up to 4 years is provided to give all parties as much time as possible to prepare for the transition.