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Sustainable Resource Initiative Policy Dialogue Framework Energy & Resources Window

Potential Changes to the Romanian RES Legislation

Final report

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Submitted to Ministry of Energy of Romania and EBRD by:

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Contents

Tables and figures

Tables

Figures

Abbreviations and acronyms

ANRE	Romanian Energy Regulatory Authority
CHP	Combined Heat & Power
ECA	Economic Consulting Associates
EU ETS	EU Emission Trading Scheme
EUR/€	Euro
FEC	Final Electricity Consumption
GC	Green Certificate
GDP	Gross Domestic Product
GFEC	Gross Final Electricity Consumption
GIEC	Gross Inland Energy Consumption
IRR	Internal Rate of Return
MIRR	Modified Internal Rate of Return
NREAP	National Renewable Energy Action Plan
OPCOM	Operatorul Pietei de Energie Electrica si Gaze Naturale
RES(-E)	Renewable Energy Sources (- Electricity)
RON	Romanian New Leu

Glossary

Categorisation of Green Certificates

Awarded	Certificates issued to RES generators upon production of eligible renewable electricity *gross* of any enforced deferral of trading
Banked	The withholding of certificates for sale at a future time
Deferred	The enforced postponement from trading of a proportion of awarded certificates
Expired	The expiry of certificate validity after which it is nullified and cannot be redeemed against a supplier's quota
Redeemed	Certificates presented by a supplier to fulfill their annual obligation
Reinstated	Certificates which have reached the end of their enforced deferement from trading

Executive summary

Purpose of this report

The Romanian Green Certificate Scheme has been operating since November 2011. In principle, it awards green certificates (GC) to accredited plants using renewable energy sources (RES) for each MWh of generation from RES for a period of up to 15 years from first generation under the scheme. The number of certificates awarded is dependent on technology. GCs are sold to suppliers at a price within a maximum and minimum range; suppliers redeem the certificates to discharge a quota obligation based on their share of total sales. The cost of the scheme is therefore borne by electricity consumers. The power generated by these projects is sold on a commercial basis.

However, the process has not gone according to plan, with the rate of development of accredited generation far exceeding expectations. The government responded to this excess generation using an assortment of measures, designed to contain the cost to consumers, affecting both earlier accreditations and new ones. These measures have an impact on consumer cost, but also on the cash flows and profitability of RES investments.

ECA has been appointed to provide an independent review of the impacts of the scheme and of the policy measures imposed and to develop scenarios of these impacts for the life of the scheme (up to 2031). The impact is viewed separately from the point of view of the different classes of consumer and from the point of view of the RES investors. ECA was then asked to look at combinations of policies that could be used going forward to improve the equitability of the allocation of costs and returns. From a consumer point of view, affordability is compared to the current burden; from a generator point of view, revenues are looked at in terms of internationally established norms for calculating a modified internal rate of return (MIRR) for each major RES technology type, which will also depend on the year of investment.

Regulatory developments

The scheme as applied in 2011 had the following changes subsequently instituted to curb the cost:

- **Reduction in GCs per MWh generated**. Due to an identified risk of overcompensation, wind, solar and hydro plants accedited after December 2013 to receive fewer certificates. This in part mitigated for cost reductions in RES technology so that new plants would not receive a return on capital in excess of that expected for earlier products.

- **Some GCs issued to be not tradable for about 3 years**. A proportion of issued GCs between July 2013 and March 2017 would not be passed to suppliers for about 3 years. This deferred the potential oversupply of certificates, but would have affected the cash flow of investments compared to expectation at the time of investment, reducing the discounted return on capital.

- **Reduction in quota for suppliers**. This reduced the cost of support to suppliers from 2014, compared to earlier expectations; it ensured, however, that there would be an overhang of unsold and unsalable GCs held by generators (the previous mentioned policy would not have been sufficient to defer all of the otherwise unsold GCs).

- **Payment capped by notified energy quantities**. For plants designated as "dispatching units" (wind and solar capacities greater than 5 MW, hydro greater than 10 MW and biomass greater than 20 MW), GCs awarded during and after July 2013 would be made based on the lower of the volume of energy delivered and the volume of energy notified for sale on the OPCOM market (such units being above the threshold for the allowance of trading via bilateral contracts). This particularly affected wind and solar generation where the forecast of generation is particularly uncertain.

- **Shortened validity of certificates**. The period between issue of certificates (eligible for sale) and when the certificate could be redeemed by a supplier was reduced from 16 months to 12 months, increasing the probability of the certificate expiring; this essentially meant that no certificates could be held over from generation in year 1 for redemption in year 3 (they would all have to be redeemed during years 1 or 2).

- **Reduction in obligation for energy intensive users**. This essentially transferred the cost obligation towards other consumers.

While not a change to the scheme design subsequent to its implementation in 2011, an important element to note is that according to Law 220/2008 new projects that are not commissioned prior to the end of 2016 will not be accredited to the scheme. This ensured that, after 2016, there would be no increase in eligible generation.

Economics of green certificates

Economics of demand for certificates

The analysis undertaken by ECA relies on certain charateristics of GC markets. Firstly, as a cap-and-trade type of mechanism with demand being short-term inelastic (being driven by a known quota rate and predictable demand), the marginal value of a GC to a supplier will tend to oscillate between the price that must be paid, if insufficient certificates are purchased and close to zero when there are surplus certificates on the market, with very little valued at prices in between. In contrast, the caps and collars on the traded price will ensure that GCs will trade at the cap (maximum) or the collar (minimum) prices. In reality, with surplus certificates on the market, then certificates will trade at the minimum price, but with many certificates going unsold.

Economics of investment

The generator model of investment will look at investment costs and operating costs, forecasts of the value of energy sold (the wholesale price of electricity) and the value and number of certificates expected to be earned and sold. These factors are put into a discounted cash flow model covering the economic life of the investment and, if the IRR matches or exceeds this risk threshold and the debt service coverage requirements are met, then the generator will invest. The discount rate applied in the model will take into account all perceived risks, such as on the wholesale price, but may not include sufficient margin to cover unanticipated changes in regulations.

One aspect of cash flow is the cost of imbalance. This applies particularly to wind and solar investments above the threshold of 5 MW for classification as dispatching units (constituting approximately 98% of wind capacity and 45% of solar capacity). The investor will predict an imbalance cost, based on estimating forecast error; where he has overforecast, the value of energy sold will be at an expected low surplus price, but underforecast will lead to an expectation of paying a high deficit price. The introduction of an intraday market in 2014 gives opportunity to partially mitigate for the forecast error dependent on its degree of liquidity. A new aspect has been the change from award of certificates on the lower of delivered energy and notified energy for generators classified as dispatching units. This reduces the number of certificates awarded by the volume of upside forecast error, compared to the previous settlement; this is modelled in the ECA analysis.

Economics of certificate banking

In the ECA analysis there has been much consideration of the impact of deferred certificate trading either on a voluntary basis or, as at present, through the deferral regulation. A certificate will rationally be withheld from the market, if this thereby leads to the price in the current year rising, but without a more intense drop in price in the next year. Banking can see certificates rolling over for several years with the expectation being that the price in year *y+1* is greater than the price in year *y* increased to include the cost of money (commercial discount rate).

The concern with banking is that hoarding of certificates in a situation of producer market power can lead to an increase in the price of those certificates sold in the current year. The ECA analysis does not model this phenomenon but notes that there is little evidence of it being a profitable strategy during a period of surplus certificates, because the predominant reason for not selling certificates in any year is not the prospect of rising prices, but the fact that such certificates cannot find a buyer at the statutory minimum price.

Market supply and wholesale price modelling

This is relevant only to the extent that it will affect wholesale prices. The price at which renewable generation is sold, which also impacts on the cost of electricity to consumers, will be determined by the marginal cost of conventional generation in Romania and the price of imports and exports. In reality, due to market coupling, the marginal cost of generation across Europe will determine pricing in Romania. The difference between Romanian prices and prices in dominant liquid markets, such as Germany, will depend on transportation costs and congestion costs. The dominant congestion between German and Romanian markets is found at the Hungary-Slovakia border so that Hungarian prices trade at a €9 premium to the German price. As a net exporter, Romanian prices trade at a discount to Hungarian price but at a net premium above German prices. The extent to which this situation persists will depend upon developments in interconnection capacity between the markets.

This also means that it is rational to model Romanian prices based on the price drivers in the German market. The German price is dominated by fossil fuel prices. This has tended to be based on the clean spark spread: the mark-up over gas plus carbon costs for an average gas-fired plant. In recent years, this has been displaced by the clean dark spread: the mark-up over coal and carbon costs. However the spark spread formula is reasserting itself and as the more traded commodity, gas will tend to cap the price at which coal can trade.

The gas price in turn is usually driven by world oil prices, with dominant contracts with Russia facilitating this. Recently, the development of shale gas and LNG has partially broken the direct contractual oil-gas price linkage, but an indirect linkage is likely to remain and the direct linkage may reassert itself. Therefore, in forecasting electricity prices the price of oil, in longer term projections, is used but with variant forecasts based on potential LNG pricing also being used.

Demand for Green Certificates

Demand for green certificates is a function of the quota and the demand for electricity. The latter is driven by consumer wealth and so can be forecasted, based on projections of GDP, adjusted for electricity intensity, which falls as GDP increases.

The quota is determined by a formula applied by ANRE, which seeks to target a given cost per MWh of support, representing the cost in 2014, when the 2020 NREAP target for RES production as a share of energy consumption was prematurely reached. Adjustments to the quota arise in part due to reductions afforded to energy intensive users, which raises the cost for other consumers. The translation of this cost into a quota is dependent on the price of a GC; for the foreseeable future, this price will be the minumum trade price.

This means that demand for GCs will only increase, effectively, if overall electricity demand increases.

In the analysis, this is a very restricted definition of affordability. Therefore, ECA's analysis also looks at affordability in terms of electricity's share (including green certificate costs) in expenditure; if wholesale energy prices fall then support for green certificates can rise without changing overall affordability.

Data sources, modelling and application

ECA has used a policy of applying publicly available sources for both historic and forecast data with the exception of data pertaining to the Romanian energy system and green certificate scheme, which were provided by the Ministry of Energy.

The model builds up a supply of GCs and a cost of generation on the supply side based on modelled projections of gas and carbon prices. Using the known information about RES generation deployment, a matrix of annual outputs by technology is projected and a profile of GCs awarded is created, including different classes of certificate, depending on whether the certificate is redeemable immediately or must be deferred.

On the demand side, projections of GDP lead to scenarios of demand for green certificates.

These main factors lead to three baseline projections: low energy and carbon cost with low demand, medium energy and carbon costs and medium demand projection and high energy and carbon and high demand. All three of these will affect the revenue for RES-E producers and affordability for consumers.

The policy variables and the date when implemented are applied to the supply of GCs in all these projections.

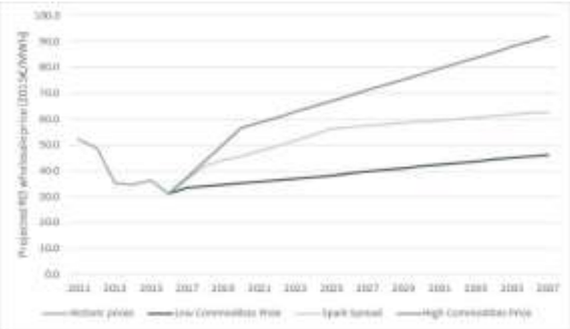
Baseline results

The GC situation at end 2016 (in million certifcates) is as follows:

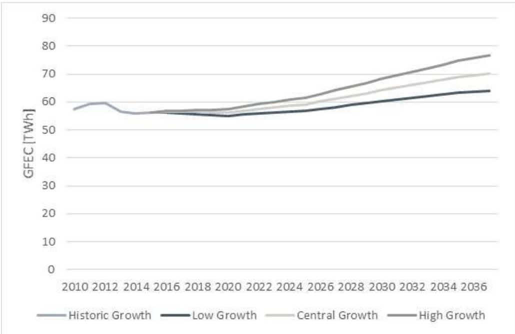
	Wind	Solar	Biomass	Hydro
GCs awarded	11.4	10.1	2.1	2.3
GCs deferred		8.8		
GCs redeemed		12.6		
GCs expired (2017)		4.4		

The main input assumptions are as follows:

Prices

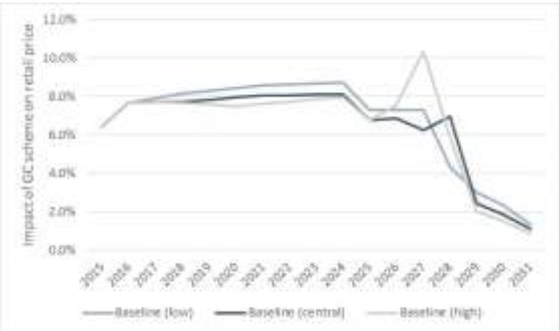


Demand

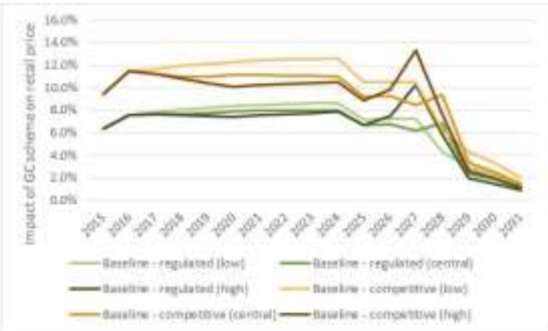


The impact of these figures on consumers along with the cost of support for redeemed GCs is as follows:

Households

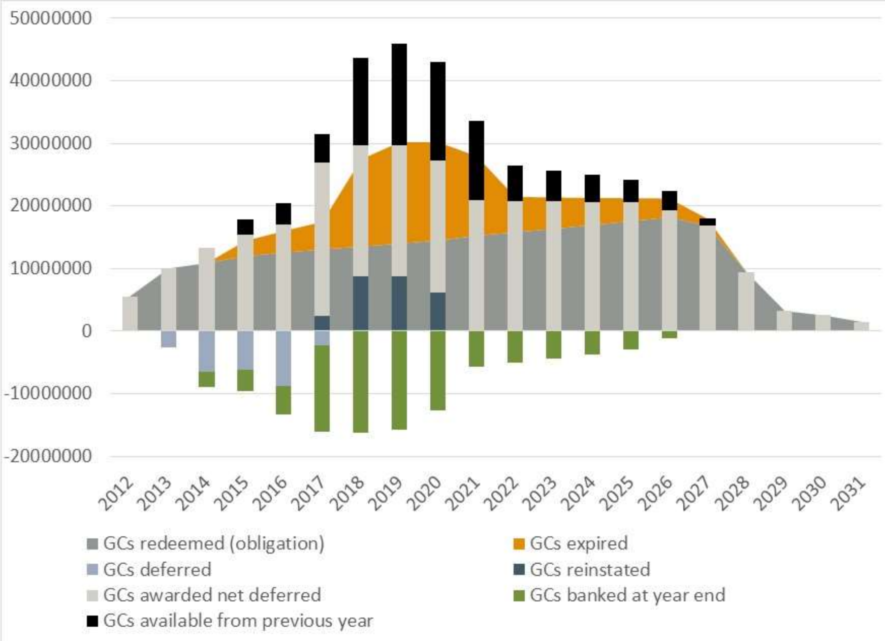


Non-households

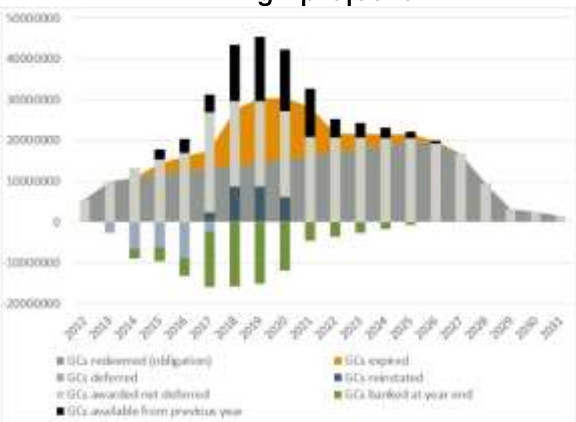


The central assumptions lead to the following breakdown of the distribution of GCs over the years:

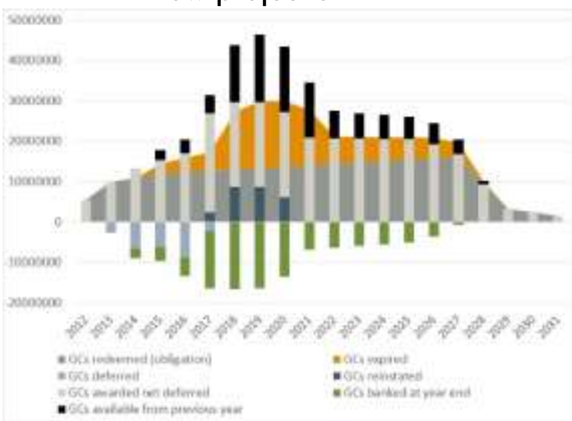
Central projection



High projection



Low projection



In all baseline scenarios, the current set of interventions leads to an oversupply of certificates, especially between 2017 and 2022, with significant numbers expiring without being sold. This represents a considerable cost to generators in all scenarios but is largely effective in containing the impact on the retail price. However, the effect on internal rate of return of generators is highly dependent on favourable non-GC revenues. The following is an example for wind generators, with the real Modified IRR[1] percentage rate dependent on year of deployment, because the changed rules affect investments differently due to when the new instrument was deployed and to which investments it applied.

[1] The Modified IRR, which allows for separate borrowing and reinvestment rates is used in this analysis, due to fluctuating cash flows, making unique IRR solutions not possible to attain in all cases.

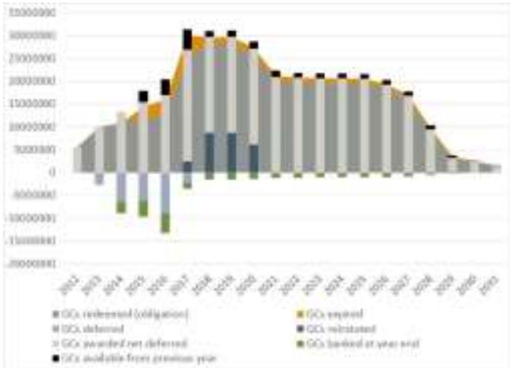
	2011	2012	2013	2014	2015
Low	2.4	2.4	1.7	1.3	2.2
Central	3.5	3.6	3.4	3.2	4.2
High	4.2	4.6	4.6	4.5	5.6

Furthermore, these results mask the negative cash flows seen in the early years, which will not necessarily cover financing costs.

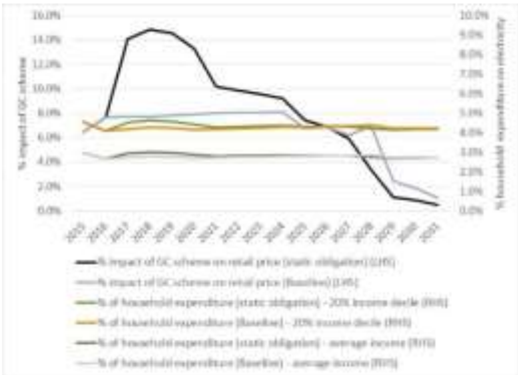
Scenarios

Most of the alternative policy scenarios that ECA analysed looked at varying the parameters of the existing policy instruments, but these differ from the original policy options by changes in policy objective.

1) "Targeted obligation" to supply of GCs

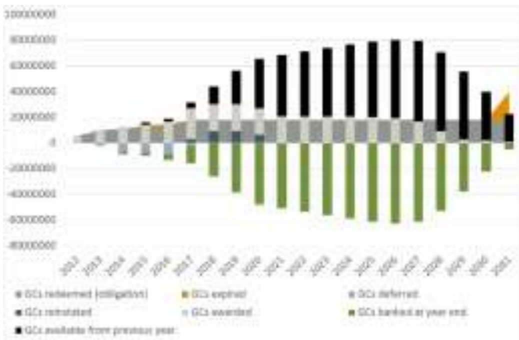


Under this scenario, the quota obligation is increased up to the forecast supply of GCs less a small surplus. This means that there ceases to be a large overhang of surplus certificates so that the vast majority of certificates can be sold in the year they are awarded. This improves producer MIRRs and by having fewer unsold GCs, helps avoid problems with unequal access to the GC market. Cash flows are improved but volatile, switching from negative to positive, to negative and finally back to positive for plant benefiting from reinstated certificates.



This improves the position of generators, as compared to the baseline case, but has a negative impact on consumers. The biggest surpluses to be carried by consumers can be found during the 2017-2020 period when the cost of the deferred certificates from the earlier period must be paid for. This is reflected by a "bulge" in consumer impact during these years (right).

2) "Static obligation" for GCs

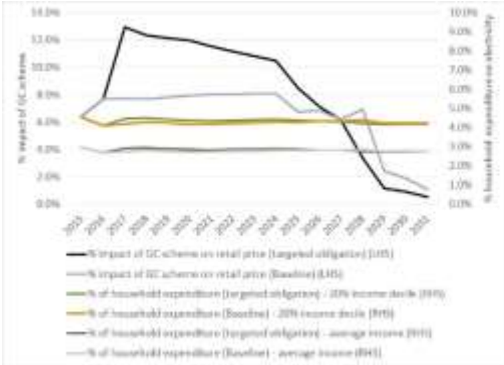


The objective of this scenario is to spread the obligation evenly across the entire period to 2031, which requires generators to be able to bank surplus certificates indefinitely. This has the effect of initially raising electricity bills as a proportion of household expenditure before allowing a gradual decline as households get wealthier. Returns for RES producers are similar to the targeted obligation scenario, while cash flows turn positive for almost all technology and year-of-accreditation groups prior to 2020, following a smoother profile than in the abovementioned "targeted obligation" case.

3) Slowing the reinsertion rate with no change in underlying quota methodology

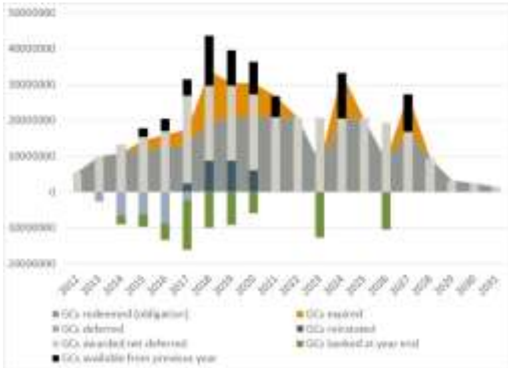
With deferred certificates reinserted into trading at a slower rate, the overhang of lost (expired) certificates should reduce. This simply extends the period over which certificates are lost to the system. Generator returns are not improved and neither is their cash flow.

4) Slowing the reinsertion rate with the targeted obligation quota methodology



This has the effect of raising costs to consumers in the earlier years, but at a less extreme rate than in the more producer-favourable scenario above. The cash flows of those accredited in earlier years recover to positive by 2017 or 2018; MIRRs remain very close to the case without slowed reinsertion, substantially improved on the baseline case, but still low in absolute terms.

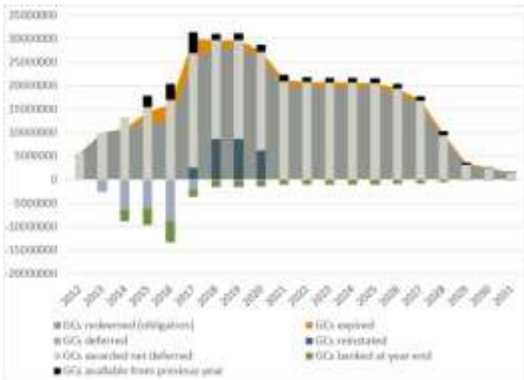
5) Varying cap and floor pricing with no change in underlying quota methodology



The effect of pricing will be most felt at the floor price because the continuing surpluses will ensure that the price will not rise above this for most of the period. However, reducing the floor price will mean that any given level of aggregate expenditure by consumers ought to buy more GCs so the quota can rise until such time as it is constrained by the total number of issued (awarded plus reinserted) GCs.

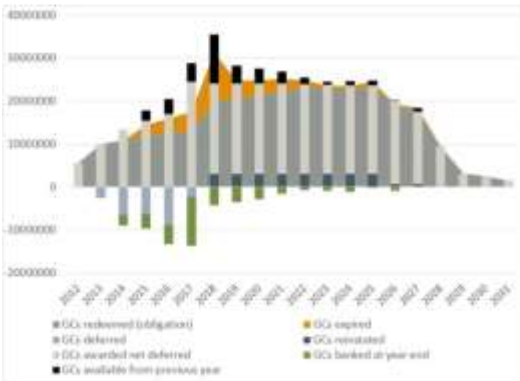
By using the previous years' GC price in estimating aggregate impact and setting the quota, the current formula paradoxically produces years when the price can rise above the floor, leading to an oscillating impact on consumer expenditure. However, because Law 220/2008 as amended empowers ANRE to set a different obligation level by varying the price it uses in calculating the quota level, the GC market price can be smoothed, although this leads to a fall in generator MIRRs (which no longer benefit from the price spikes). This does not address negative generator cash flows, which last up to the mid 2020s.

6) Varying cap and floor pricing with the targeted obligation quota profile



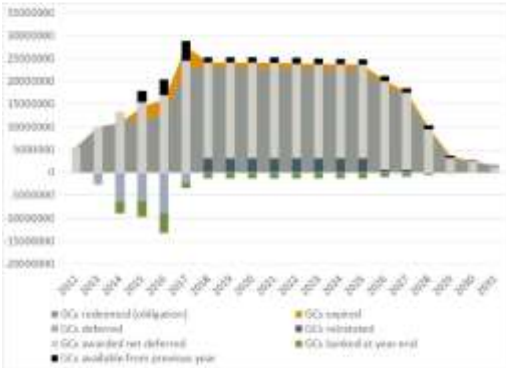
An alternative is to use the scenario where the quota is set in accordance with the availability of GCs but with a lower minimum price. This helps lower the impact on consumers in the years prior to 2020 but does nothing to smooth the impact across time, while RES producer returns are significantly hurt as a straight pay-off.

7) *Lowering minimum price and slowing insertion rate (no change to quota methodology)*



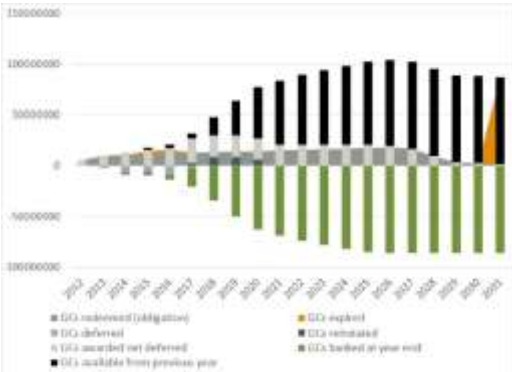
This combination produces a profile much closer to actual demand for certificates, leading to fairly minimal banking or expiry. The effect is to spread expenditure more evenly across the scheme period and revenue across generators, with the share of consumer incomes going on electricity being smoothed (which would be due to this being ANRE's policy in setting the annual quotas). However the delay in cash flow for generators has a negative impact on MIRRs which also remain weak.

8) *Lowering minimum price and slowing insertion rate in the targeted obligation quota profile*



As with the similar case without a reduced minimum price, this combination eliminates the bulge in the period to 2020, smoothing insertions up to 2026-2028. This delays the impact on consumers but does not overall have a detrimental effect on the share of electricity in their expenditure. It has a detrimental effect on generator MIRRs and prolongs the occurance of negative cash flows the lower the minimum price selected.

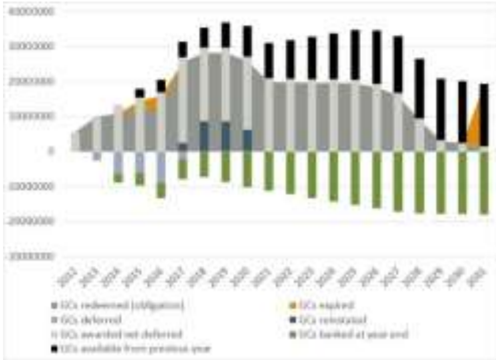
9) *Varying the banking rules with no change in quota profile*



An alternative to forced banking (the deferment in allowing some certificates to be traded) would be to allow indefinite banking, so that certificates would be held until they could be sold at the minimum price. As the chart shows, this has a marked change in the profile of redemptions, but even in 2031, many certifcates remain unsold. This makes no change to the consumer support spending profile and does not improve generator cash flow or MIRR.

10) Varying the banking rules with targeted obligation quota profile

A compromise scenario, where some targeting of the surplus occurs so that banking volumes do not get excessive, is shown here. Targeting a surplus in the annual volume of issued (awarded plus reinstated) GCs annual surplus in order to encourage trading at the minimum price becomes quickly unnecessary as the banked volumes are alone more than sufficient to ensure this occurs. The "static obligation" case (Scenario 2 above) is effectively a variant of this approach.



Conclusions

These scenarios are all explained in more detail in the body of the report. By targeting the obligation in some way to the volume of GCs available in the market, the market will be encouraged to clear with many less GCs remaining unsold and mitigating for unequal access to the GC market between RES producers. However, due to the planned reinsertion of previously deferred GCs for trading in the period 2017-2020, such an approach would result in a "bulge" where the impact on consumers is raised significantly. Slowing the reinsertion rates can help smooth this profile. From this point, setting the minimum price becomes a straight pay-off between the consumers and producers and what all the presented scenarios have in common is that there remains a funding dilemma for Romania. Given what has already been invested then there are two ways of dealing with the dilemma: either consumers must pay more or producers must earn less.

In large part, the funding damage for the producers has already been incurred, with negative cash flow for these producers from 2013 to 2016 if they have been unable to sell some or all of their certifcates. This can potentially be ameliorated by different policy options going forward, but to regain positive cash flows prior to 2020 and give producers reasonable rates of return would require a large increase in the proportion of bills spent on the GC scheme. If such increases prove unacceptable, then the resulting financing gap may require financial measures external to the GC scheme design to be considered (e.g. securitisation or partial payment through general taxation).

Key results from selected policy combination scenarios are provided below.

Impact on consumer bills (%) of selected policy combination scenarios

Year	'16	'17	'18	'19	'20	'21	'22	'23	'24	'25	'26	'27	'28	'29	'30	'31
Targeted obligation methodology with 5% surplus and extended reinsertion (no change to price levels)																
Impact %.	7.7	13.0	12.4	12.1	12.0	11.6	11.2	10.8	10.5	8.5	7.1	6.2	3.4	1.1	0.9	0.5
Current quota methodology with extended reinsertion and no indexation of minimum and maximum prices																
Impact %.	7.7	7.1	7.6	7.7	7.8	7.9	7.9	8.0	8.0	6.6	6.0	9.8	5.4	1.8	1.4	0.8
Targeted obligation methodology with 10% surplus, extended reinsertion and no indexation																
Impact %.	7.7	11.4	10.8	10.4	10.1	9.6	9.1	8.7	8.3	6.6	5.4	4.6	2.4	0.8	0.6	0.3
Static obligation methodology with indefinite validity																
Impact %.	7.7	10.4	10.1	9.9	9.8	9.4	9.2	8.9	8.6	7.0	6.8	6.7	6.6	6.4	6.3	6.2

Source: ECA

RES-E generator estimated Modified IRRs (real terms) for selected policy combination scenarios

	Average Modified IRR (%)for RES-E capacity by year of accreditation					
	2011	**2012**	**2013**	**2014**	**2015**	**2016**
Targeted obligation methodology with 5% surplus and extended reinsertion (no change to price levels)						
Wind	4.1	4.3	4.1	3.5	4.3	-
New hydro	5.3	6.0	6.6	-	7.5	-
Biomass CHP	4.4	4.3	4.3	4.4	4.9	5.6
Solar PV	5.7	6.3	8.5	6.4	6.8	8.8
Current quota methodology with extended reinsertion and no indexation of minimum and maximum prices						
Wind	3.5	3.6	3.4	3.2	4.1	-
New hydro	4.4	5.2	5.8	-	7.1	-
Biomass CHP	3.1	2.9	2.8	3.2	3.9	4.8
Solar PV	4.6	5.3	7.5	5.8	6.3	8.4
Targeted obligation methodology with 10% surplus, extended reinsertion and no indexation						
Wind	3.8	3.9	3.6	3.2	3.9	-
New hydro	4.8	5.5	6.0	-	6.9	-
Biomass CHP	3.7	3.5	3.2	3.1	3.4	4.0
Solar PV	5.2	5.7	7.7	5.7	6.1	8.0
Static obligation methodology with indefinite validity						
Wind	4.1	4.3	4.1	3.5	4.3	-
New hydro	5.2	6.0	6.5	-	7.5	-
Biomass CHP	4.2	4.1	4.1	4.4	4.9	5.6
Solar PV	5.7	6.2	8.4	6.3	6.7	8.7

Source: ECA

1 Introduction

1.1 Background

Origins of the Green Certificate Scheme

The Romanian Green Certificates (GC) Scheme under analysis here became operative in November 2011. It was introduced initially through Law 220/2008. This law set up a framework whereby producers in the eligible technologies were awarded tradable certificates. These certificates were to be awarded to the producer based on output and to be given for up to 15 years from the receipt of accreditation as a RES producer. No impact assessment was undertaken prior to notification of the policy.

On the supplier side was an obligation to buy green certificates in proportion to their customers' annual offtake. The regulation set up a minimum price for the GCs intended to protect the revenues of the generator, and a maximum price meant to protect electricity consumers. The price range was set at €27 – 55/GC (annually indexed by EUR inflation since 2011).

The power generated by renewable sources is sold on a commercial basis and, the generators receive GCs on top. The number of GCs per MWh depends upon the generation source (wind, solar, biomass, hydro etc.). For the two most common technologies (wind and solar), the number of GCs to be received was initially set at 2 GCs/MWh and 6 GCs/MWh for wind and solar respectively. Since 2014, the GCs have had to be traded on OPCOM, the Romanian power exchange although there are exceptions for the small generators; prior to 2014, bilateral trading of GCs was allowed.

Regulatory developments

From the point of view of encouragement of investment in renewable generation, the scheme proved extraordinarily successful. This was mainly due to apparent over-compensation in the size of the quota and the number of certificates awarded per MWh, particularly as cost of deployment for RES declined. Various measures were therefore instituted by statute in order to reduce the impact of the increasing cost of funding on consumers and industry:

- **ANRE Overcompensation Analysis**. In March 2013, Romanian energy regulator, ANRE, published an overcompensation analysis for 2012, which concluded that there was, on average across technology groupings, overcompensation for wind, solar and new mini hydro power plants. ANRE proposed (GD 994/2013) a reduction in the number of GCs granted per MWh for plants accredited after December 2013:
  - New wind farms: from 2 to 1.5 GCs until end 2017 and 0.75 GCs from 2018
  - Solar: from 6 to 3 GCs
  - New mini hydro power plants: from 3 to 2.3 GCs/MWh.

This reduction was meant to lower the future supply of GCs from new projects.

- **Governmental Emergency Ordinance (GEO)** of 10 June 2013, notified to the European Commission. This deferred the trading of some of the GCs issued from the period July 2013-March 2017 to April 2017- December 2020 for solar and hydro plants, and to January 2018 to December 2020 for wind farms. The deferment applies to existing plants accredited up to 31 December 2013:

  - For wind farms, 1 of the 2 GCs were postponed
  - For solar, 2 out of the 6 were postponed
  - For mini hydro, 1 out of the 3 were postponed.

  This change in regulation has the effect of dramatically reducing the GC supply for the period July 2013-March 2017 for capacity accredited before the end of 2013 but with a corresponding increase in supply for the period 2017-2020.

- **Law 23/2014 which amended Law 220/2008 and affected the demand for GCs, by decreasing the mandatory renewable energy quotas for 2014 consumption to 11.1%** from the quota of 15% established through previous modifications (Law 139/2010) of Law 220/2008. The amendments introduced through Law 23/2014 stipulated a process whereby ANRE recalculates the GC quota annually. For 2016 this has been recalculated to be 12.15% as compared to the indicated quota of 17% established through the previously mentioned modification of Law 220/2008.

  By reducing the obligation of electricity suppliers to buy GCs from the market, there has been a reduction in demand of GCs far bigger than the reduction of supply from other measures. This change had a significant revenue impact on investments, affecting old and new projects by altering the marketability of the GCs. The Romanian authorities justified this change by the fact Romania has already achieved its 2020 RES target and so wished to focus on affordability for consumers.

- **Payment on notified energy only for "dispatching units"**. Plants designated as dispatching units include wind and solar capacities greater than 5 MW, hydro greater than 10 MW and biomass greater than 20 MW. The legislation changed also by capping the entitlement to GCs to only the corresponding notified electricity deliveries and not purely to the metered deliveries. This meant that GCs were now awarded on the lower of metered energy and notified energy. Although an intraday market has been operated by OPCOM for a few years, it has only operated in its current form and really attained significant volumes since 2014 (at 0.3% of day ahead market throughput in that year[2]). Intraday trading can continue until 3 hours before physical delivery. Given the difficulties of accurately forecasting wind and solar output, we have applied a discount to the volume of energy for which certificates are awarded based on international experience of forecasting error for these technologies.

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[2] Although this appears to be a low percentage, it is not significantly below international norms for intraday activity compared to day ahead activity.

- **Shortening the validity of a GC to 12 months**. The validity period for a GC was reduced to 12 months from the previous 16 months, bringing forward the expiry of those certificates that could not be sold in an oversupplied market.

- **Redistribution in supplier obligation due to GC levy exemptions for energy intensive users**. Since 2015, energy intensive companies such as aluminium smelters, steel mills and petrochemical plants are exempted from the payment for GCs for up to 85% of their GC requirements. This exception has been approved by the EC and is in place starting with July 2015 for the first exemption agreements. Given that the overall supplier quota is not changed, this implies an increase in the quota for all other users.

It should be noted that there will be no new accreditation of projects. After earlier awarded accreditations enter into production during 2016, no new plants will be accredited.

Finally, Romania has instituted a Feed-in Tariff (FiT) scheme for small (<1 MW) projects. At time of writing, consideration is being given to allowing some projects in receipt of GCs to convert to the FiT scheme. There are complexities involved related to awarded GCs that may not be tradable or else have not yet been sold. It is not known what impact there will be from these small projects leaving the GC scheme but it is thought the impact will be minimal on GCs issued overall.

The earlier over-investment has led to emergency adjustments, which have changed the fundamentals of previous investment decisions leading to potential hardships. One issue that needs to be worked through is that adjustments made to address consumer cost have led to a position where the GC market is failing to clear such that producers are seeing GCs going unsold and ultimately failing to be monetised before they expire; deferment has only partly addressed this and also leads to potential overhang of certificates on the market once they start being made available again (in addition to those being awarded based on current energy deliveries).

1.2 Objectives and scope of the report

This report offers an objective view of the operation of the GC market and expectations of how it will develop. The ultimate purpose is to set out options for resolving difficulties.

This report must tackle the issues from two perspectives:

- **Consumers**. What is an affordable pathway for paying the cost of RES support based on historic commitments made to producers? Affordability is a partly subjective measure and at a minimum should take into account total consumer expenditure and changes in wholesale electricity prices and not just GC costs.

- **RES generators**. What is a reasonable return and cash flow on investments made? The postponement measures on GC trading as well as the short-term allocation of GCs while markets are not clearing will need to be assessed. At the same time energy revenues from generation will change and, while their business plans should have allowed for this, the return on projects where much of the cash flow has been deferred will need to be assessed.

Therefore, the scope of the analysis will involve scenarios of future generation and consumption and the profile of allocation of GCs. This is to be used to plot basic scenarios of expected revenues for generators and costs to consumers looking forward as far as 2031, which will determine the impact of existing policies and price limits for GCs.

The next step will involve varying policy options moving forward and their impact on generator revenues and consumer prices, and suggestions of how combinations of policies can optimally balance the competing objectives of generators and consumers. This will work, therefore, as a regulatory impact assessment of past and future interventions in the market.

1.3 Layout of the report

In this report we cover:

- In Section 2 we set out the methodological approach to the analysis including forecasting methodologies as well as the economics of green certificate pricing and of affordability assessment.
- Section 3 summarises the source of data for past and current values as well as public data sources used in price and volume projections.
- Section 4 provides a numerical and descriptive analysis of the evolution of the market since 2011 as well as an analysis of the impact of regulatory interventions on GC issue and redemption in 2016, giving us a baseline for projections.
- In Section 5 we provide our baseline projection of supply and demand as well as prices for wholesale electricity, green certificates and retail electricity sales so that we can assess the impact of current policies on consumers and on RES producer cash flows and incomes.
- Section 6 looks at different regulatory interventions individually and in combination and their impacts on consumer prices and RES generator revenues.
- Finally, in Section 7, we provide a summary and key conclusions of the analysis.

The report is supplemented by annexes on key aspects of the analysis and data.

2 Approach

The green certificate mechanism is a variant of a cap and trade-type mechanism that is rooted in the legislation-determined demand and price for green certificates. However, in large part, the demand for certificates can be considered as a by-product of the demand for electricity and, in terms of affordability, the cost of certificates added to the cost of electricity has a direct bearing on the demand level as will be explained below.

The supply of certificates is also determined by legislation, which sets out which generators are eligible to be awarded certificates and how many certificates will be awarded to them. Furthermore, certificates are an add-on value to revenues from sales of electricity and so investment decisions of generators will be determined by the full revenue streams expected from both energy sales and certificate sales.

Therefore, in describing the economics of the whole mechanism, we need to look at the entire electricity industry and so we follow a conventional approach to description of the industry which starts with the economics of generation and moves through to demand.

2.1 The economics of the green certificate mechanism

2.1.1 Economics of demand for green certificates

As stated, the mechanism is a cap and trade type of mechanism. In any year, the volume cap is set by ANRE and devolved to suppliers as a quota: a percentage of their customers' offtake that must be covered by redemption of green certificates. There is a complication in the way ANRE calculates that quota due to reduced obligations for certain large industrial customers but this does not change the principle.

Suppliers pay a penalty for each green certificate they fail to redeem to meet their quota and the penalty rate sets the value of the green certificate to the supplier in a situation of shortage. The penalty rate is 110 €/certificate not redeemed (indexed by EUR inflation). However, in a situation of surplus green certificates, the value to suppliers of an extra green certificate in that year falls to close to zero because once the quota is reached, there is no benefit to the supplier from holding an extra certificate (while the certificate remains valid for the following year its value will only rise above zero if the market is forecast to be in approximate balance or deficit for that year). This is a common feature of cap and trade mechanisms, the value tends to vary between the avoided penalty price and zero with very little scope for a price in between; a similar situation is found, for example with the EU ETS where emissions certificates currently trade at around 5 €/certificate despite the penalty rate being 100 €/certificate.

There is of course a margin of error around both the quota and the supply of certificates during any year. The quota will vary according to the offtake of the suppliers' customers, which is not fully determined at the start of the year due to changes in weather or in the supplier's portfolio over the year. For this reason, suppliers may aim to purchase up to, maybe, 105% of their quota to avoid risk of penalty. Similarly on the supply side, although the supply of certificates in any year will be known because the deployed capacity of eligible plants is well known or easily predictable, weather can affect the volume of certificates actually earned in the year, with year-to-year variations in average wind generation and average insolation being examples. If both supply and demand for certificates are very similar then the net surplus or deficit of certificates predicted at the start of the year will be uncertain, and certificates will be valued at between the penalty rate and zero rather than at one or other of those rates. Nevertheless, uncertainties within the Romanian GC scheme are reduced through the closure of the scheme to new entrants after 2016, a mid-year check on deviation from the ex-ante estimate and an ex-post reconciliation based upon realised GC eligible RES-E production, awarded exemption volumes and electricity consumption levels.

2.1.2 Economics of supply of certificates

Green certificates are awarded in accordance with the regulations depending on the technology deployed by the accredited generator but are still awarded in direct proportion to the energy generated during the year. A generator will therefore seek accreditation and invest depending on its perception of revenue over the economic life of the project.

The generator will prepare a project plan for the investment looking at the discounted cash flows over the life of the project and will invest if the Internal Rate of Return exceeds its target rate, debt service coverage considerations permitting. The cash flows consist of annual costs (investment in the initial years, maintenance, fuel costs in a few cases and revenues from the sale of energy and sale of green certificates. In the majority of cases (wind and solar as well as small-scale hydro), the significant costs are upfront investment costs, which will be well known at time of investment and so the key elements that must be forecast are the future value of energy and future value of certificates.

In the case of Romania, where no new plants will be accredited, the investments had all been deemed to have sufficient return on capital based on predicted values and volumes of energy and certificates awarded to make the investment worthwhile. However, excess investments and subsequent regulatory interventions have changed the cash flow profiles for these generators. It is the impact of these interventions that need to be evaluated.

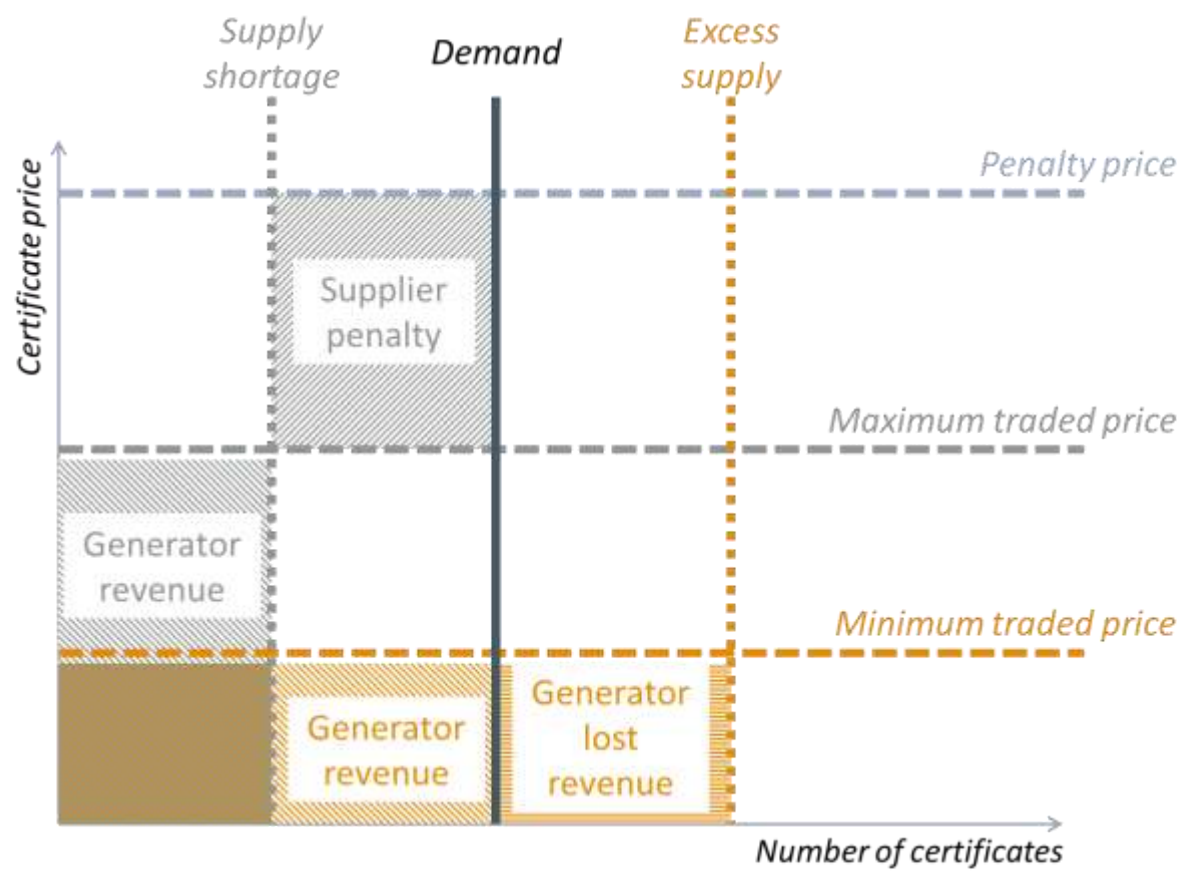
2.1.3 Effect of the maximum and minimum prices of certificates

Figure 1 is a diagrammatic representation of green certificate pricing. It introduces a feature of the Romanian Green Certificate scheme, which is the maximum and minimum prices at which certificates can be traded via the OPCOM centralised market, or for small generators via bilateral contracts. It shows the two cases of:

- **Shortage of green certificates**. These are shown in grey on the diagram. Generators only earn up to the capped price for each certificate and suppliers are faced with the penalty for the shortfall. This is intended to limit supplier costs for purchasing green certificates but, in fact, it represents a transfer to government of the shortfall payments. Individual suppliers that fail to purchase sufficient certificates will risk heavy losses.

- **Surplus of green certificates**. These are shown in light brown on the diagram. Generators sell up to the level of supplier demand at the minimum price but, because demand is fixed, all surplus certificates go unsold and generators make no revenue. Certain generators may earn nothing from green certificates in that year. On the other hand, supplier costs are minimised allowing them to fill their quotas at the minimum price. The minimum price was designed to assure generators of a minimum revenue but fails to do this due to the number of certificates unsold.

Figure 1 Economics of GC pricing



2.1.4 Economics of regulatory interventions

As described in the introductory section of this report, various regulatory interventions were imposed to address emerging problems. The economics of these are described here.

Reduction in number of certificates awarded per MWh for new investments

This policy addressed the earlier over-compensation of the initial scheme. As such, it allowed normal rather than excess profit on new investments. It therefore slowed but did not stop RES investment. This was a rational response to previous over-compensation.

Reduction in supplier obligation percentage

It was determined that the cost of support had become too great for consumers. This was against a background of excess investment leading to Romania prematurely meeting its NREAP target. As Figure 1 shows, an excess in RES generation will not lead to an increase in cost to suppliers because such surplus certificates will go unsold. Therefore, the policy contradicted the earlier policy of setting a quota path that was originally deemed affordable. The reduction in quota ensured that more certificates would go unsold than before and so affected generator income relative to their reasonable expectations at time of investment.

Deferred allocation of certificates

With an emerging surplus of certificates being awarded, it was decided to reduce the number that would be awarded immediately with the withheld certificates due to be given about 3 years later. For any given quota (and hence demand for certificates), this had the effect of potentially giving a positive value to the deferred certificates, which would otherwise have expired unsold. The value to generators would be discounted by the 3-year delay and can be regarded as partial compensation for the quota reduction. However, in the year when the certificates are returned to the generator, the supply of certificates is increased (newly awarded certificates based on eligible generation plus the deferred certificates) and so it is not clear that the deferred certificates, once returned would be sold anyway.

This policy can be viewed as an attempt to add value to certificates that would otherwise have lapsed at zero value. The success of the policy will depend on the level of demand for certificates in the year in which the deferred certificates are returned to the generators.

Reduction in the life of a certificate – economics of banking

When the scheme started, certificates could be held for 16 months before being redeemed. This was reduced to 12 months. Under the original scheme, therefore, a certificate unsold in one year could be redeemed in the following year when, hopefully, demand had increased, the quota had increased or supply had reduced (because the following year was less windy or for other similar reasons). Reducing the life of a certificate by 4 months makes this harder but does not rule out deferring redemption into the next year because certificates are awarded monthly based on the previous month's physical generation.

Deferring redemption into a new year is known as 'banking'. Limiting the life of a certificate is driven by fear that, in an oligopoly situation (either on the generator side or the supplier side), banking could be used to create artificial shortage forcing the price of certificates up in the current year.

In fact, the economics of banking is more general. A certificate would be banked and redeemed in a later year when:

$$Price_{y+1} \geq Price_y * (1 + r)$$

Where:

$Price_y$	is expected certificate price in year y;
r	is the interest rate the banker could expect.

This equation works in a narrow range of circumstances. If the price of certificates is at the minimum in year y it will only be above the minimum in year $y+1$ if the surplus that saw the price dropping to the minimum is small and can reasonably be expected to become a deficit in the following year. If there is a substantial surplus in year *y* it can reasonably be expected to continue into the following year. If there is shortage in year *y* then there will be no reason to bank because the price in year *y+1* cannot be higher as it is already at the maximum[3].

In banking where supply and demand are reasonably balanced – the only circumstance where banking becomes worthwhile – then it should be noted that banking may raise the price in year *y* but may well have the effect of lowering the price towards the minimum in year *y+1* because more certificates will be available in that year (newly awarded certificates plus the banked certificates).

The situation becomes more complicated because a banked certificate can effectively be redeemed several years later: the banker will redeem the certificate in year *y+1*, but will then bank a fresh certificate from year *y+1* for redemption in year *y+2*, and so on.

The deferred allocation of certificates discussed above could have been achieved by allowing banking over multiple years.

2.2 Supply of conventional generation

2.2.1 Conventional generation capacity

In theory, capacity will be developed whenever the long-run marginal cost of electricity (expected average annual wholesale price) exceeds the levelised cost of new build generation. This type of analysis will tend to be used in long term capacity adequacy analyses that Transelectrica will undertake for its submissions to the ENTSO-E 10 year statement. The precise mechanics of the analysis is of less concern to us because the main issue for both RES revenue analysis and affordability is only the resultant wholesale price.

As is discussed below, in an increasingly interconnected electricity system with market coupling, the price is becoming a European price anyway. Therefore, in analysing conventional generation capacity, the main issue is whether it will result in Romania being a net exporter or a net importer. Currently, Romania is a net exporter, with the price therefore lowered by the cost of export to the main markets, which are Bulgaria, Serbia and Hungary.

However, there is considerable congestion on the Hungary-Slovakia border such that wholesale prices in Hungary tend to be some 9 €/MWh above the NW European (German) price. The cost of export capacity from Romania to Hungary was over 4 €/MW for transfer capacity in 2015 and prices in Romania are consequently 4-5 €/MWh below the Hungary price. The net position is that Romania wholesale prices remain approximately 4 €/MWh above those in NW Europe.

Romania remains a net exporter and can expect to continue in this way with projected new construction of nuclear capacity at Cernavoda. However, this will tend to replace aging thermal capacity.

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[3] There is a possibility that, due to inflation, it may be possible that the earnings in year y+1 could go up but only where the interest rate was very low or even negative in real terms.

Therefore, in projecting forward for the purposes of Romania RES projections, we are interested in two main elements:

- The cost of congestions between Romania and NW Europe. These congestions are likely to continue and so a reasonably stable mark-up in prices can be expected:

  - Hungary mark-up over German prices of €9;

  - Romania mark-down from the Hungary price of about €5;

  which leaves a relatively stable mark-up of Romania prices over German prices of 4 €/MWh;

- The degree to which Romania is a net exporter or a net importer. If Romania becomes a net importer then energy will flow from NW Europe, via Hungary into Romania. If this happens then the Romania price will approximately equate to the Hungary price because there is not going to be net congestion for flows out of Hungary to Romania (current price about 8 €c/MW, although if there is significant import this could rise).

In terms of non-RES generation, the projected balance is only relevant to the extent that it might turn Romania from exporter to importer; else the relationship between the Romanian and German price should hold broadly constant.

2.2.2 Price of conventional generation

Investors in green technologies can expect to be price takers with marginal prices set either by Romanian conventional generators or by cross-border markets. With market coupling there is increasing convergence between spot prices in day ahead markets except when there is transmission congestion. Although, for the medium term, there will continue to be congestion along many European borders, and particularly on the Hungarian-Slovak border (which affects Romania's access to NW European price coupling), this will only affect prices in a limited number of hours through the year.

On this basis, a general model of interlinkage of prices can be made affecting Romanian wholesale prices.

The model we consider most appropriate for describing European electricity pricing is based on what is known as a mix of the clean spark spread and the clean dark spread. In both cases, the electricity price is based on a fairly fixed mark-up of the fossil fuel price made up as follows:

$$
\begin{aligned}
Price_{ef} = \quad & Price_f / Conversion_f + \\
& Price_c / Conversion_{cf} + \\
& k
\end{aligned}
$$

Where:

$Price_{ef}$	is the price of electricity in €/MWh where the marginal price is set by fossil fuel price *f*;
$Price_{f}$	is the cost per MWh input of fossil fuel *f*;
$Conversion_{f}$	is the number of MWh of electricity generated using 1 MWh of fossil fuel *f*, which is 0.50 where the fossil fuel is gas and 0.38 where the fossil fuel is coal;
$Price_{c}$	is the forward price in €/tonne of 1 tonne of CO_2 emissions traded under the EU Emissions Trading Scheme;
$Conversion_{cf}$	is the number of MWh of electricity generated while emitting 1 tonne of CO_2 while using fossil fuel *f*, which is 2.78 for gas-fired plants and 1.27 for coal-fired plants;
k	is the fixed costs per average MWh generated by a typical plant burning fossil fuel *f*, which is 3.5 €/MWh for a gas-fired plant and 6 €/MWh for a coal plant.

From this formula, it is clear that the electricity price is in a stable relationship with the fossil fuel price and so forecasting that fuel price will give a reasonable forecast of the electricity price provided that that fuel is the marginal fuel.

Across Europe, prices tend to be set either by coal-fired plants or by gas-fired plants. In the years up to mid-2016, European gas prices dropped less steeply than coal and were relatively expensive so there was a greater tendency to use coal, which became the marginal fuel for price setting purposes. This meant that the relevant European electricity/fuel price relationship in these years was the dark spread. Very recently, gas prices have fallen and so the spark spread relationship has returned. Indeed, the normal relationship is the spark spread because the substitutability of gas and coal in electricity generation tends to mean that the more traded commodity (gas) will tend to cap the price at which the other commodity (coal) can trade. However, for projection purposes we use the formula:

$$Price_e = \quad Min\ (\ Price_{eg}\ ,\ Price_{ec}\ )$$

Where:

$Price_{e}$	is the European price of electricity in €/MWh;
$Price_{eg}$	is the price of electricity in €/MWh where the marginal price is set by gas;
$Price_{ef}$	is the price of electricity in €/MWh where the marginal price is set by coal.

It should be noted that, in NW Europe, the parameters are derived only from coal and gas plants even where there is significant hydro and nuclear capacity. This is because hydro is either a pure price taker (run-of-river type) or else will price at avoided price of thermal (reservoir type), and nuclear has very low variable costs and so will never be the price-setting marginal plant.

Therefore, for projecting forward, we will calculate a clean spark spread and clean dark spread in all scenario, take the lower of the two for each year under analysis and apply the transportation cost uplift to arrive at the projected price of wholesale energy in Romania.

Gas price projections

The price of gas into Europe is very much an international price. There is a mix of gas sources dominated by flows from Russia, Norway and through LNG cargoes. Traditionally pipeline gas has been priced based on an index of the price of oil cargoes (in turn usually indexed against the ICE Brent Crude marker). This linkage was favoured by Gazprom and had dominated pricing in Europe for many years. Several things have subsequently changed:

- The financial crisis in 2008 led to a reduction in gas demand worldwide;
- Shale gas development in the USA turned that country from a net importer into a zero importer and then a net exporter of LNG;
- Qatar, Australia and other places developed LNG liquefaction facilities and the infrastructure for major LNG exports worldwide including Europe;
- The political crisis between the EU and Russia over Ukraine led to a wish in Europe to diversify away from dependence on flows of gas from Russia;
- Possibly due to global warming, several mild winters have reduced demand for gas for heating.

All these factors have moved the gas market away from oil price linkage and towards spot pricing with LNG shipping and handling costs providing a floor to the market. It is possible that oil-price linkage will be restored and there will be a tendency for longer-term marginal costs of oil and gas extraction and transportation to move in step anyway. But for now, most international projections of gas prices have moved to independence from oil prices.

Coal price projections

The primary use for internationally traded hard coal worldwide is in electricity generation, in direct competition with gas. Therefore, it is reasonable to expect that the prices, after adjusting for add-on costs of carbon emissions penalties will tend to move in parallel. In practice, the gas price has historically tended to be a cap on coal prices rather than a pure parallel price movement.

However, the period from mid-2011 to end 2015 saw a steady decrease in coal prices that was only replicated in gas prices from start 2014 bringing the clean dark and spark spreads broadly back together from summer 2016. While international forecasts foresee a rebound in prices for both commodities, that rebound is expected to be sharper for gas than coal. One potential explanation being the increase in renewables generation and closure of coal plants due to emissions concerns continues to create the conditions for overcapacity in coal supply.

Wholesale electricity price model for Romania

Our methodology follows the following steps:

- **Gas price model**. This follows the international projections of gas pricing. We review scenarios of oil price projections and apply the traditional ratios of gas to oil price in most scenarios because oil price are often projected forward for more years than are gas prices, but we will include a decoupled scenario assuming LNG remains abundant.

- **Carbon price model**. The current EU ETS price is based on allocation of emission rights based on historic emissions. Because it is a cap-and-trade mechanism, if the obligation is less than the available allowance (emissions certificates) then the value of the certificates drops to close to zero; if there is a shortage of certificates then the price will be close to the penalty price (100 €/tonne). However, it is inconceivable that European politicians would allow the price to exceed the price at which certificates trade internationally and so the high price scenario would be capped at the expected world price of carbon. Carbon price projections are very difficult because there is no objective valuation beyond avoidance of penalties.

- **Clean dark/spark spread price**. This methodology was described above. There is an established relationship between the marginal fuel (gas or coal) and electricity price and this is expected to be maintained as cost of fuel per MWh generated plus cost of carbon per MWh generated plus mark-up to cover marginal new generator fixed costs.

- **Romanian price**. This is initially calculated in Euros and is the mark-up of €4 over the projected spark spread price to reflect transmission congestion cost between Romania and NW Europe; scenarios where Romania becomes a net importer would see the mark-up increase to the Hungary price, which will be a mark-up of €9.

The wholesale price of electricity is of use in developing the consumer price but also the revenue from energy sales of renewable generators. In most cases, the annual average price is perfectly sufficient to determine the revenue for any generator. This is because the sales of different generators will tend to be regardless of time of day or time of year so that even where, in the case of wind, for example, the dispatch on any day is uncertain, on average through the year any generator will receive the annual average price[4].

The exception is solar output. This is a daytime output and so tends to be higher than average price because, although solar will not sell much energy during the evening peak, it will not be selling any energy at night when prices are lowest. Therefore, in modelling solar energy revenues we apply the following steps:

[4] To check this assumption for wind power we undertook a similar diurnal analysis to that described for solar PV. While there is evidence that production is not entirely uncorrelated with time of day (higher yields were noted for late evening and lower yields in late morning) the weighted average revenue received remained within 0.0001% of the average daily price.

- **Solar output profile**. Develop diurnal profiles of solar output per MW of capacity by hour using OPCOM production data.
- **Daily price profile**. Based on OPCOM's day ahead prices for a typical year, develop a revenue profile by multiplying the output profile by the hourly prices.
- **Solar premium**. Compare the average price per MWh of solar farms with the average price derived from OPCOM baseload price and calculate a percentage mark-up for solar farms.

Solar sales will be concentrated in summer months and will be low during the winter when prices tend to be higher although this effect may be offset by increasing penetration of air-conditioning units and has therefore not been considered within the model.

2.3 Supply of RES and Green Certificates

In the baseline case, all green certificates have been allocated and are already being issued or deferred for existing plants or else will shortly be allocated for the remaining new plants authorised and being developed under the scheme. Therefore, the model of supply of green certificates is mechanistic. The components of the model are as follows:

- **Average capacity factor by technology**. For each of the main technologies determine how much annual energy will be generated from a MW of generating capacity.
- **Profile of generation deployment**. For each technology, plot the MW developed in each year and the MW available in each year to be awarded green certificates, noting that each investment will earn green certificates for up to 15 years (dependent on technology category).
- **Profile of energy generated**. For each year of investment and technology, calculate annual output by applying the capacity factor to the capacity developed.
- **Profile of certificates awarded**. For each year and technology, calculate:
  - Number of certificates awarded in that year
  - Number certificates deferred in that year
  - Number of deferred certificates returned (reinstated) to the generator.

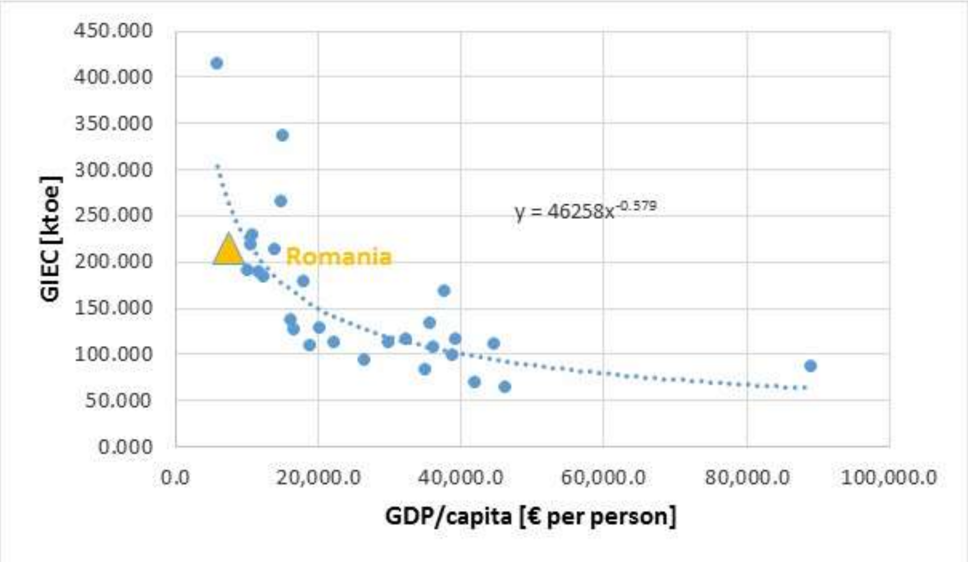
This model forms the basis for assessing both the supply of certificates in any year and the supply of energy, noting that energy will continue to be generated even after the plant is no longer eligible to receive certificates.

2.4 Demand in Romania

Demand level

Electricity demand is a function of GDP growth and GDP level. As a relatively poorer EU country, the energy intensity (units of energy per unit of GDP) is relatively high; as GDP grows, energy intensity (including its sub-component, electricity intensity) will tend to fall. Figure 2 plots the energy intensity data for the different EU countries. In order to calculate future demand for electricity in Romania, we apply the energy intensity formula maintaining Romania's current differential to the trend, to GDP projections to obtain an estimate for Gross Inland Energy Consumption (GIEC). We then use the EC Reference Scenario to ascertain the share of electricity in GIEC. The EC Reference Scenario projects energy trends for all EU Member States on 5-year intervals to 2050[5].

Figure 2 Energy intensity of European countries



Source: Eurostat

Sector shares

Various factors will affect sector shares including the development of heavy industry at one end of the scale, and the growth in air conditioning use at the other end. No absolute trend can be developed without a full demographic and industrial development forecast. Therefore, we project forward sector shares as being unchanged over the time horizon of this analysis.

Retail prices

The price of electricity to consumers will be made up from the following elements:

[5] http://ec.europa.eu/energy/en/data-analysis/energy-modelling

- Wholesale price – derived from the model explained in Section 2.2.2; plus
- Network costs – these costs will vary by voltage tier, with heavy industry facing the lowest costs and residential consumers, the highest; plus
- Green certificate quota costs; plus
- Taxes, supplier margin, metering costs, etc.; plus
- Cross-subsidy elements between consumer classes (if any).

For modelling purposes, it is assumed that network costs and taxes, etc. will remain constant and so the only effective variables will be wholesale costs green certificate costs.

Affordability

There are two methodologies for determining affordability:

- Law 220/2008 required ANRE to monitor the impact of the GC scheme on end users from 2014 and also empowered ANRE to set a methodology for the annual mandatory quota. In doing so ANRE has taken a minimalist approach to affordability by determining the cost of green certificate quotas at the historic level set in 2014 (effectively as a cost per MWh) and deeming this the affordable level in the case that the National Objective on RES is met or exceeded for the year preceding the assessment. This means that the volume of the quota is changed if the minimum price (in a surplus situation) is changed by law or if final consumption levels change. The methodology is described more fully in Section 3.
- A more orthodox approach would look at the total cost of electricity in the consumer classes' total income; if total income goes up then the consumer class can afford more in the way of green certificate expenditure and if wholesale electricity prices fall then consumers can also afford to pay for a higher quota. In practice, affordability is really an issue for heavy industry (with discounts on green support already mandated) and residential consumers, and in particular poorer households.

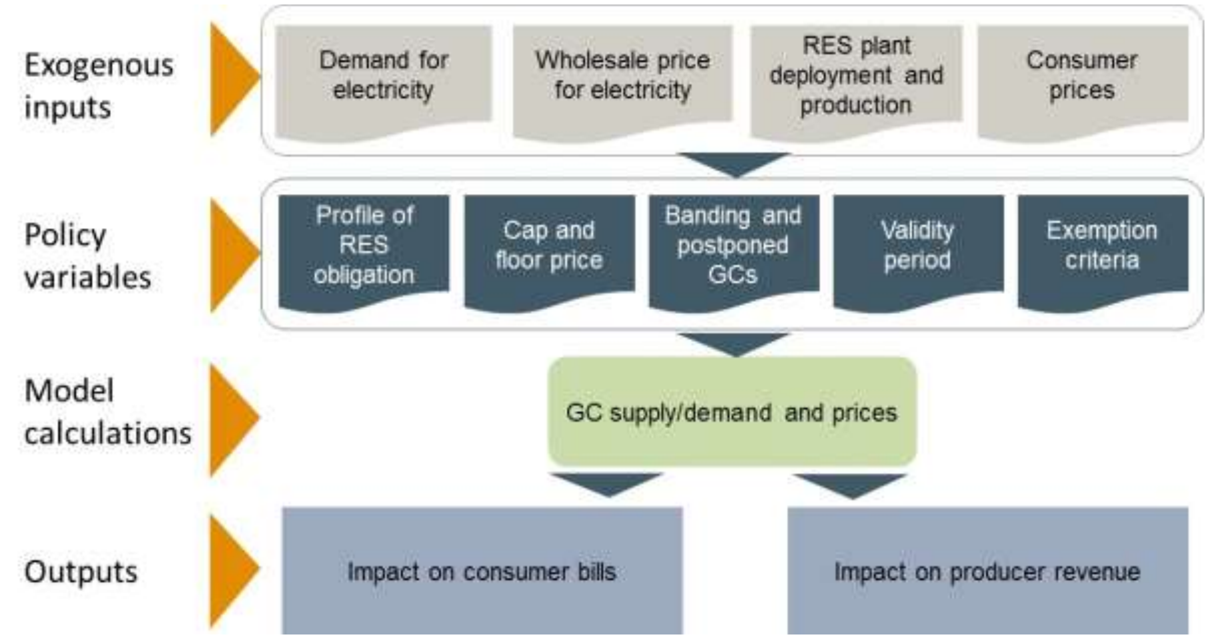
Following the ANRE lead, our concern will be with regard to changes in affordability rather than in absolute levels. Although there are more objective methodologies used in various analyses worldwide that seek an absolute affordability measure (in relation to monthly income), we will accept current levels of electricity cost as a share of household incomes and consider affordability relative to that share. This means that, as household income rises with GDP, the resultant electricity-intensity adjusted consumption level will allow for increases in support to green certificate purchase (i.e. increase in quota) provided this does not increase the share of electricity costs in household income; similar considerations can apply to other classes of consumer.

2.5 Structure of the model

As described above, supply and demand for green certificates will be dependent both on the regulatory structure of the scheme (penalty prices, methodology for setting the obligation, max and min prices) and on external factors affecting the supply and demand for electricity. Our model first establishes a central projection regarding these external factors together with two sensitivity cases (high and low) based on a combination of demand and power price projections while maintaining the current GC regulatory framework. Together these represent the "baseline policy projections" described in Section 5.

We then aim to estimate the impact of altering the regulatory structures for the GC scheme. This approach is summarised in Figure 3.

Figure 3 Approach to model



Source: ECA

3 Data sources

Information and data regarding the Romanian energy system and green certificate scheme have been provided directly by the Ministry of Energy. We have used these in combination with publically available data from Eurostat, OPCOM and other relevant international institutions and exchanges. Regulations have been provided as English translations of the Romanian originals. We have not been able to verify the accuracy of these translations.

3.1 Non-policy inputs to the model

This section details our sources for historic, current and projected input data regarding key external variables which affect the supply and demand for green certificates. Background information on datasets used is provided in Annex A1.

3.1.1 General economic and demographic data

Table 1 summarises data sources used in gathering historic and projected data for relevant general economic and demographic parameters. All economic data have been adjusted to 2015 EUR or 2015 RON using the inflation data detailed. Projections are written in italics under the column "timeframe".

Table 1 General economic and demographic data

Data	Source	Timeframe	Comments
GDP (Romania and EU-28)	Eurostat	2011 to 2015	-
	IMF World Economic Outlook	*2016 to 2021*	IMF forecasts up to 5 years ahead
	EC Reference Scenario	*2025, 2030*	Projected percentage increase applied forwards from IMF figures for period 2022 -2036
Population	Eurostat	*2015, 2020, 2030*	Assume linear trend between data points
Inflation (US)	Bureau of Labour Statistics	2011 to 2015	-
	OECD	*2016, 2017*	Values rounded to nearest decimal place and 2017 figure used for full period to 2036
Inflation (Eurozone / Romania)	Eurostat	2011 to 2015	Hamonized index of Consumer Prices (HICP)
	European Central Bank (ECB)	*2016, 2017, 2020*	2020 figure used for all years 2018-2036
Exchange rate €/$	OANDA	2015	Average rate for 2015 used and assumed to remain constant over time period
Exchange rate RON/€	OANDA	2015	Average rate for 2015 used and assumed to remain constant over time period*
Romania income distribution	INSSE	2015	Used to derive impact on both 20% income decile and average income households

Note *: Romania is a member of the European Exchange Rate Mechanism (ERM) II which seeks to stabilise exchange rates with the EUR. The rate has remained in a relatively narrow band between 4.4 and 4.6 since mid-2012.

3.1.2 Energy demand data

- Gross inland consumption and final energy consumption data are taken from Romania's Energy Balances of 2011-2014 as reported by Eurostat.
- Gross final electricity consumption (GFEC) and final electricity consumption (FEC) data for 2010-2015 have been supplied directly by ANRE which differs from that reported in Eurostat in that it includes consumption tied directly to power plants and own consumption by power plants.
- Energy Balance data have been used to guide the sectoral breakdown of FEC by end user.

- Projections from 2016 onwards for absolute levels of gross inland consumption are based on the GDP and population projections and use the energy intensity profile presented in Figure 2. Energy carrier shares are calculated using the same percentage shares indicated in the EC Reference Scenario. Sectoral shares for electricity use are fixed to the latest Energy Balance data (2014).

- Projections for future line losses are then calculated assuming an annual improvement in losses of 1% (of the losses value) with respect to the year before. These are then added to the FEC projections to generate gross final electricity consumption (GFEC) projections.

3.1.3 Fuel and power price data

Section 2.2.2 described the process used to generate power price projections for the Romanian wholesale market. Data sources used in this analysis are detailed in Table 2.

Table 2 Fuel and power price data

Data	Source	Timeframe	Comments
European natural gas price	Intercontinental Exchange (ICE)	April 2010 to December 2016	Monthly futures contracts for TTF Netherlands Virtual Trading Point
	World Bank (Commodities Market Outlook July 2016 edition)	*2015 to 2025*	Data for 2015 corroborated against TTF results. For 2026 onwards, price held steady at 2025 forecast as gas prices de-link from oil (Central Case only).
Crude oil price projections	World Bank (Commodities Market Outlook July 2016 edition)	*2015 to 2025*	Data series extended to 2036 by extrapolating 2020-2025 trend
	International Energy Agency (IEA) World Economic Outlook (WEO) 2015	*2020, 2025, 2030*	Provides alternative case to World Bank. New Policies Scenario projection with linear interpolation used
Hard coal price	ICE	January 2013 to December 2016	Monthly futures contracts for the Amsterdam, Rotterdam and Antwerp region
	World Bank (Commodities Market Outlook July 2016 edition)	*2015 to 2025*	Australia Newcastle FOB projection with shipping margin of US$8/t applied.

Data	Source	Timeframe	Comments
German/Austrian wholesale power price	European Energy Exchange (EEX)	January 2013 to December 2016	Baseload Phelix power price. 2016 average price based on current monthly futures.[6]
	ECA derived	*2017-2030*	Derived through Spread analysis described in Section 2.2.2
European Emission Allowances (EUA) price	ICE	January 2011 to December 2016	Monthly futures contract pricing
	ECA estimates	*2030*	Linear trends between 2016 and 2030 to different final levels assumed
Romanian wholesale power price	OPCOM	2015	Day-Ahead Market data taken as monthly averages[6]
	ECA derived	*2016 – 2036*	Derived from EEX price as described in Section 2.2.2
Romanian retail power price	Ministry of Energy	2015	Provided by consumer class and voltage level
		2016-2030	Elements of price other than wholesale or GCs assumed constant through study

3.1.4 Capacity, generation and costs of RES electricity

Green certificates are issued in proportion to the generation of electricity from RES plant. Different policy criteria relate to RES-E plant built in different years and with different technologies (see Section 3.2 below). Details of RES-E installations by year and their capacity factors are therefore required for the analysis. Cost information is also required in order to estimate the impact of policy changes on the returns for RES-E producers. Table 3 summarises the sources for these data.

Table 3 Capacity, generation and costs of RES electricity data

Data	Source	Timeframe	Comments
Eligible RES-E installations by technology	Ministry of Energy	2011-2015	New installations assumed to occur on average at mid-point of year
	Ministry of Energy	*2016*	Current expected installations for 2016

[6] See Table 40 in Annex A2 for a comparison of yearly average day-ahead prices for EEX and OPCOM.

Data	Source	Timeframe	Comments
RES-E capacity factors	ANRE (Overcompensation analyses 2012-2015)	2012-2015	Single Capacity Factor per technology – average of figures used for 2016 onwards
RES-E investment costs	ANRE (Overcompensation analyses 2012-2015)	2012-2015	Linear trend between 2012 and 2015 figures used to estimate costs for 2011 and 2016
RES-E operations and maintenance costs	ANRE (Overcompensation analyses 2012-2015)	2012-2015	Average of figures used for 2016 onwards

3.2 Policy variables

Once the input elements exogenous to the GC scheme are established it is necessary to define the inputs (data and formulae) related to the scheme's design. These are the policy variables which will be investigated in Section 6. Table 4 details the regulations and other documentation used to define historic and current (baseline) inputs. Box 1 below then summarises the amended calculation methodology for setting the annual quota for green certificates.

Table 4 Information on policy variables

Policy variable defined	Legislation / Regulation	Period affected	Comments
RES-E/GC obligation	Law 220/2008 as amended by Emergency Ordinance 88/2011	2011-2013	Originally set a trajectory to 2020 based on set percentages of gross final electricity consumption
	Emergency Ordinance 57/2013 Order 114/2014	2014-	Amended Law 220/2008 (Law 23/2014) to empower ANRE to set quota based on (i) degree of achieving national RES objectives and (b) consumer impact
	Order 101/2015, Order 2/2016 Order 16/2016	2015- (methodology understood to be same as was used for 2014)	Sets out methodology employed by ANRE for determining annual quota. Calculations are provided in annual "Notes" issued by ANRE.
Banding of Green Certificates	Law 220/2008	RES-E accredited during 2011-2013	Defines number of GCs per MWh generated by technology category

Policy variable defined	Legislation / Regulation	Period affected	Comments
	HG 994/2013	RES-E accredited during 2014-2016	Amends the number of GCs per MWh for new installations from start 2014 following Overcompensation Analysis 2012*
Maximum and Minimum GC prices	Law 220/2008	2011-	Sets maximum and minimum trading prices in 2011 Euros to be indexed to Eurozone inflation sourced as detailed in Table 1
Deferment of certificates	Emergency Ordinance 57/2013	For RES-E accredited during 2011-2013 (affect years 2013-2017)	Defers a proportion of GCs earnt in July 2013-March 2017 to years 2017-2020 by RES generators which were accredited during years 2011-2013

Note *: A further Overcompensation Analysis undertaken in 2015 concluded that solar PV may be at risk of overcompensation but as yet no additional changes have been made to banding levels as a result.

Box 1: Methodology on establishing annual quotas

Emergency Ordinance 57/2013 amended Law 220/2008 (Law 23/2014) to empower ANRE to set the RES-E and corresponding GC quotas and obligation based on the dual considerations of (i) achieving national objectives (with respect to RES) and (ii) impact on consumers.

Order 101/2015 (from Law 23/2014, transposed into Order 11/2014) as subsequently amended, outlines the methodology ANRE uses to undertake this task. Romania's commitment for the share of RES in gross final energy consumption in 2020, and associated interdemiate trajectory, as required by Annex I of EU Directive2009/28/EC, are adopted as the national objective. The methodology for setting RES-E and GC obligation then depends on whether the implied target as given by the trajectory was achieved for the year preceeding the analysis.

If the target has been achieved then the allowed average impact (in RON per MWh terms) on the consumer tariff is set equal to that for the preceeding year in nominal terms. If the target has not been met then the allowed impact rises in proportion to the shortfall vis-a-vis the target for the precdeeding year.

In order to convert the average impact ($I_{GC,}$ which includes exempted consumption) into a RES-E and GC obligation the methodology first establishes a capped quantity of RES-E (RES-E_{CAP}) which may be supported in the coming year by the scheme by dividing the total impact on consumers by the expected price of a GC, and multiplying this by the average MWh of RESE-E produced per GC issued in that year, as follows:

$$RESE_{CAP}\ [MWh] = \left(\frac{I_{GC} * FEC}{price\ of\ GC}\right) * \left(\frac{RESE\ produced}{number\ of\ GCs}\right)$$

The number of GCs issued for that year is calculated to be inclusive of any which are recovered following previous postponement. However, as the RES-E volume is only that for generation within the year, the above formula can result in the RES-E quota being sharply reduced relative to the previous year. Nevertheless the required number of certificates, which is what impacts supplier costs and RES producer revenues, will rise or fall only with changes in electricity demand, the price of GCs and/or the volume of eligible RES-E generation.

The is because the ratio of the capped RESE-E quantity to the total expected RESE-E production is muplitipled back by the number of GCs expected to be issued to obtain an etsimated aggregate obligation for the number of GCs to be redeemed by suppliers. This figure is converted into a quota by dividing through by final energy consumption net of the exempted quantity:

$$Quota\left[\frac{GC}{MWh}\right] = \left(\frac{number\ of\ GCs * {}^{RESE_{CAP}}/_{RESE}}{FEC\ net\ of\ exempted\ quantity}\right)$$

Crucially, however, if the cap is equal to or greater than the etimated level of eligible RES-E which will be produced in a given year, then the GC quota is instead calculated by simply dividing the estimated number of GCs issued (awarded plus reinstated) in that year by the net FEC. This means a situation of substantial undersupply and unavoidable penalties is unlikely to occur.

Source: ANRE Order 101/2015, Order 2/2016, Order 16/2016

4 Development of Romanian power sector

4.1 Current situation

4.1.1 Developments to 2015

In common with much of the EU, Romania saw low levels of GDP growth in the years 2010 to 2012, averaging just 0.3% per annum in real terms. While growth picked up significantly to 3.5% in 2013, unusually this was not immediately reflected through increased demand for electricity which actually saw a decline on the previous year. Table 5 summarises GDP growth and final electricity consumption over this period.

Table 5 GDP growth and final electricity demand 2011 - 2015

	2011	2012	2013	2014	2015
GDP growth	1.1%	0.6%	3.5%	3.0%	3.7%
FEC [TWh]	46.8	46.7	45.2	46.7	47.3

Source: Eurostat

In terms of sectoral shares, energy-intensive industrial demand has seen a small decline from 31.0% in 2010 to 29.1% in 2014, counterbalanced by increases in the share for residential and tertiary sectors. This reflects a common trend for middle income countries as household incomes rise and inefficient heavy industries are gradually shut-down or modernised.

The generation mix in Romania is split four ways between thermal (40%), nuclear (17%), hydro (27%) and other RES-E (15%) sources. For the last three years Romania has been a net exporter of electricity to more expensive markets in Hungary and the Balkans. Since November 2014, Romania has been had its Day-Ahead Market and interconnection capacity coupled with those of Hungary, Slovakia and the Czech Republic (the "4M Market Coupling") allowing for more efficient operation of that capacity. However, as noted in Section 2, constraints remain on the Slovakia-Hungary border restricting the ability for price arbitrage across the region and lifting Romanian prices relative to the Czech Republic and Slovakia.

As has been the case across the EU, wholesale power prices in Romania sharply declined between 2011 and 2014 with an aggregate drop in price of 34% before levelling out through 2015. Table 6 summarises the average Romanian DAM price for each of the years 2011-2015.

Table 6 Annual average Romanian wholesale power price

	2011	2012	2013	2014	2015
Average price [€/MWh]	52.13	48.8	35.34	34.66	36.40

Source: OPCOM

Conversely, Romanian retail prices increased in 2013 as regulated prices for large consumers were phased out and increases in taxes and levies applied to household prices. Prices nevertheless remain low by European standards with an average price of 424 RON/MWh (approximately 95 €/MWh) in the regulated market and 276 RON/MWh (€62/MWh) in the competitive market. The competitive market accounted for approximately 70% of FEC in 2015.

Green Certificate prices were at the maximum price of €57.4/GC in 2012 before falling to an average of €44.1/GC in 2013, suggesting rare balance between supply and demand was established in that year. Following the regulatory changes made to the calculation of the quota, oversupply in 2014 caused prices to slump to the minimum regulated price where it has remained ever since.

4.1.2 Situation in 2016

Romania's first half GDP growth for 2016 has proven strong and on course to meet the IMF forecast of a 4.2% annual rate. This would indicate an increase in annual FEC in the order of 2.2% with respect to 2015 levels.

Wholesale power prices in the first two months of 2016 mirrored the continued falls seen in the EEX Phelix price for Germany/Austria. While a small recovery has taken place in the summer months the weighted average of settled monthly forward contracts up to August 2016 and current trading prices for monthly forward contracts from September to December 2016 in the Phelix area is just €27.3/MWh. Taking the standard transportation margin assumed for the Romania price of €4/MWh gives a 2016 forecast for Romanian average wholesale power of €31.3/MWh.

Following the methodology for defining the GC quota described in Section 3.2, ANRE set the estimated obligation[7] for 2016 by capping the impact on consumer bills to previous years' levels. This was due to the recorded over-achievement of RES-E share relative to national targets for previous years. The allowed impact was held at 35 RON/MWh (in nominal terms) and a 1% increase in FEC on 2015 was assumed. This resulted in the ratio of the obligated GCs for suppliers to awarded GCs (excluding those deferred) being approximately 65% and a resultant significant oversupply in GCs expected for the year.

Due to the oversupply prevalent in the market, green certificates have unsurprisingly continued to trade at the minimum regulated price of €29.4/GC. As oversupply is forecast to continue through 2017 also, all unsold GCs from 2016 will either expire or displace a new GC from 2017 which in turn expires. Assuming uncertainty results in demand for GCs being 5% over the obligation amount, a volume of GCs equal to the remaining 30% of issued GCs in 2016 will therefore remain unsold and earn zero revenue for the given RES-E producers.

From November 2013 to March 2017, RES-E plant eligible to earn GCs and installed prior to 31 December 2013 have a proportion of the GCs deferred to between 2017 and 2020. The proportions deferred for each technology form are as follows:

- 1 GC per MWh for new hydro plant up to 10 MW in capacity
- 1 GC per MWh for wind power plants

[7] The obligation is "estimated" as it is revised ex-post upon confirmation of actual FEC and RES-E production volumes

- 2 GCs per MWh for solar power plants

The resulting projected breakdown of GC by category for 2016 is shown in Table 7. Due to the 12 month validity, unsold GCs will expire at various points during 2017. While it is possible some of the GCs unsold in 2016 will find a buyer before expiring in 2017, as noted above due to the current oversupply this will only be at the cost of a trade for a newly produced 2017 GC.

Table 7 Forecast flow of 2016 GCs

	Wind	Solar	Biomass	Hydro
GCs awarded	**11,357,783**	**10,061,337**	**2,128,281**	**2,254,691**
GCs deferred	**8,821,560**			
GCs redeemed	**12,566,051**			
GCs expired (2017)	**4,414,480**			

Source: ECA

5 Baseline policy projections

In this section we establish high, central and low case projections for each of the demand level and wholesale prices, leading to high, central and low case projections overall. We report the results for each case under the current regulatory framework – collectively these are our baseline policy projections.

5.1 Generation projections

5.1.1 Wholesale power price

RES-E plant will receive revenue from both wholesale power prices and the sale of green certificates (where demand exists). Our methodology for deriving wholesale power price projections in the Romanian market was described in Section 2.2. The input parameters we vary are the cost of fuel and cost of carbon. We have defined three cases:

- A "**Low Commodities Price Case**" where subdued economic growth sees only a gradual recovery in the current low fossil fuel prices for both gas and coal but particularly the latter. Slow growth and related political pressure also acts as a break on the carbon price which recovers very slowly to just €17/t (in 2015 EUR) by 2030. Coal as the cheaper generation source continues to set marginal prices in the central European power markets. Projections for coal are based to 2025 on the World Bank CMO figures with the trend between 2020 and 2025 extrapolated thereafter to 2036.

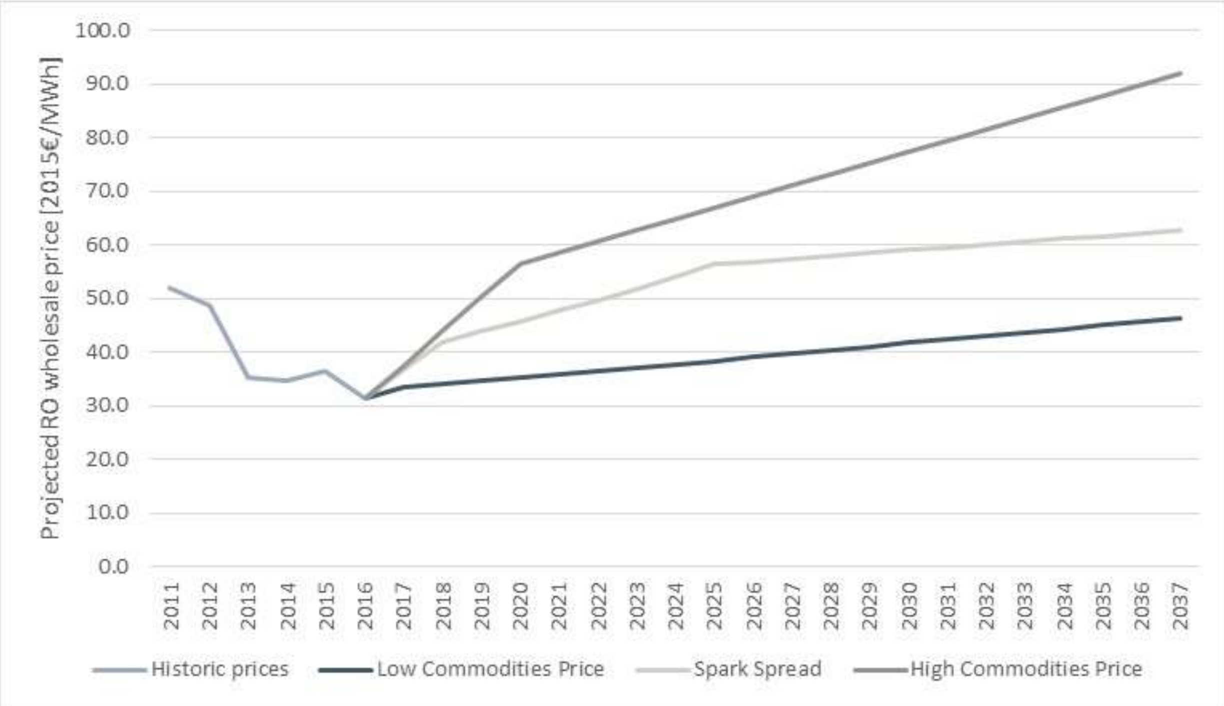
- A central "**Spark Spread Case**" where natural gas follows the oil price with a brief rebound from the extremely low prices noted in first half 2016 before the long-term trend towards increased competitive pressures in the European natural gas market sees a continued decline in its price relative to crude oil. The very low coal prices of recent years and its advantage over gas are, however, not sustained and so gas returns to be the marginal fuel. Gas price projections are based on World Bank CMO figures to 2025 and then held level in real terms to 2031. Revisions to the EU ETS scheme under this case are assumed to be sufficient to see a steady rebound in the price to €26/t.

- A "**High Commodities Price Case**" based on the IEA 2015 WEO New Policies Scenario (NPS) reflecting a Europe of stronger GDP growth and a quicker rebound in fossil fuel prices back towards the levels of 2010-2011. This case also sees a stronger rebound in EU ETS prices to €37/t by 2030. Coal again is the cheaper fuel and thus the clean dark spread sets wholesale power prices.

In all cases, we have followed the EC Reference Scenario in assuming that Romania will be a net exporter of power but that congestion on the Slovakian-Hungarian border will remain and so the price will remain at a premium to the projected German price.

Figure 4 presents the three Romanian wholesale power price projections based on above fuel and carbon price cases, a constant level of fixed costs and a constant assumed premium for the Romanian market with respect to the Phelix (German/Austrian) price region[8]. Both the Spark Spread and High Commodities Price cases incorporate a rebound from the very low fossil fuel prices of 2015 and 2016 as the market reacts to the extreme combination of oversupply and weak demand. Indeed a small recovery is already apparent in oil prices with natural gas typically having a three to six month lag in its corresponding reaction. While a degree of decoupling has taken place and is indeed expected to continue to occur, the move towards a more competitive gas market is by no means complete in Europe and therefore the oil/gas price relationship is likely to continue to influence natural gas prices at least in the near to mid-term. The Low Price Case assumes no such recovery takes place. Price growth is supported by the corresponding assumed rise in carbon costs under the High Commodities Price and Spark Spread cases in particular.

Figure 4 Romanian wholesale power price projections



Source: ECA

5.1.2 Renewable energy generation

National RES objectives as stated in Annex I to Directive 2009/28/EC are given in terms of the supply of all energy from RES sources with respect to the gross consumption of energy in Romania. The required renewable energy for electricity (as opposed to heat or transport) is assumed to follow the trajectory outlined in Romania's National Renewable Energy Action Plan (NREAP). RES -E projections to 2031 (final year of scheme) are therefore required for:

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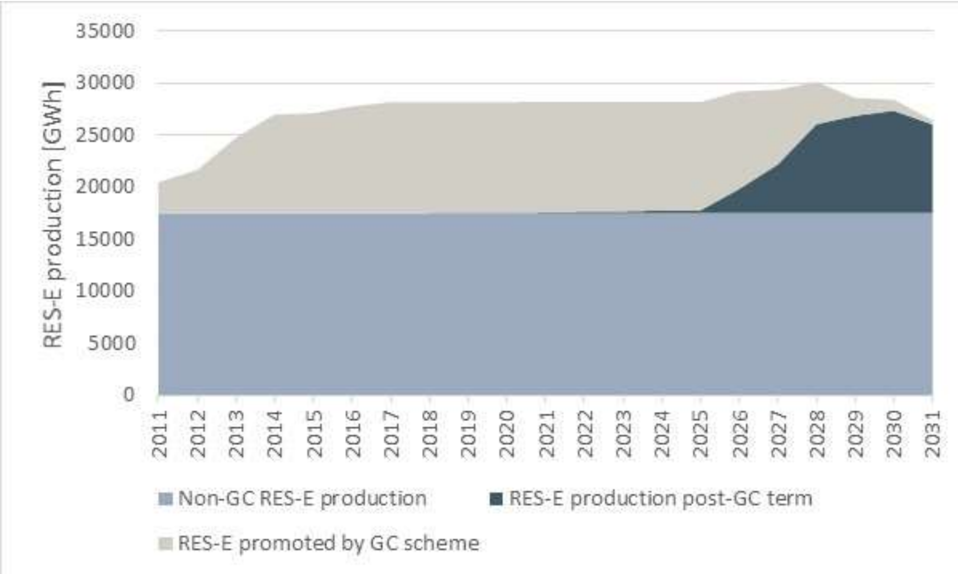
[8] Although it is possible that infrastructure investments will lead to an increased correlation between German and Romanian prices, we have assumed that the level of congestion in the European network leading to the differentials seen, on average, since market coupling may well be maintained, particularly as the focus of investments will be driven by the pattern of wind production in Europe rather than being dictated by a need to relieve congestions in East-West/North-South conventional energy flows; these assumptions are not backed by full network analyses.

- RES-E generation from plant which are eligible to receive green certificates
- RES-E generation from plant which were previously eligible to receive green certificates
- RES-E generation from plant which, due to technology and capacity categorisations, are not covered by the green certificate scheme (primarily large-scale hydropower)

Calculating RES-E generation from current and previously eligible plant requires understanding of capacity installed per technology category per year and average capacity factors. RES-E generation from plant not covered by the obligation scheme are assumed to consist solely of large hydro plants and is set to be flat for the period of the study. Figure 5 summarises the projected generation from each category of RES-E plant.

Figure 5 Estimated RES-E production by category



Source: ECA

5.2 Demand projections

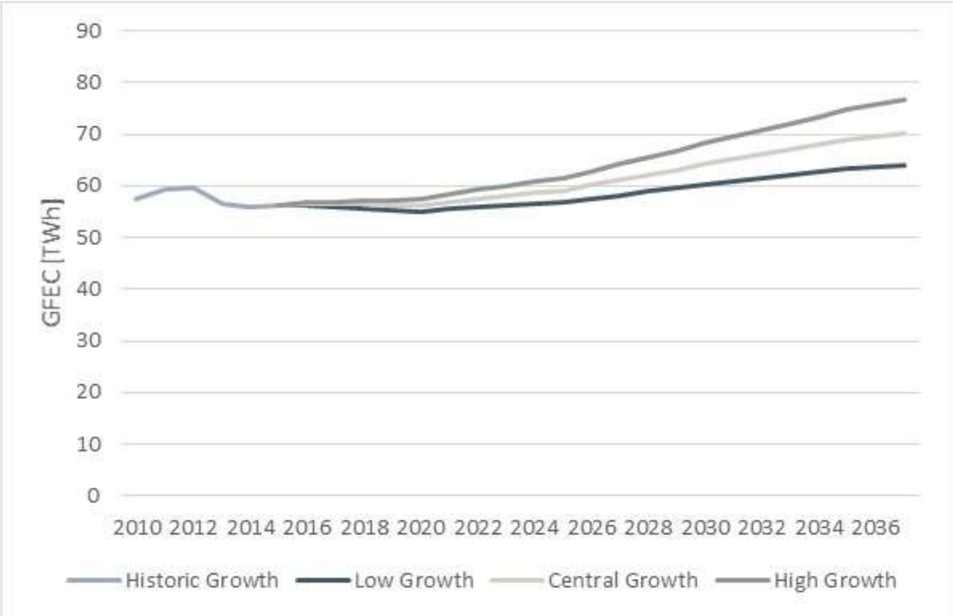
Our approach to generating demand projections, based upon its link with GDP and energy intensity, was described in Section 15. Our three cases are therefore variants on the expected GDP growth rate as follows:

- For our **"Low Growth Case"** we subtract 1% per year from the current IMF forecasts to 2021. Thereafter we adopt the 5-year average growth rates assumed in the EC Reference Scenario and again subtract 1% per year from these. We note that for overlapping years the EC Reference Scenario growth rates are significantly lower than those of the IMF.
- For our **"Central Growth Case"** GDP increases as per current IMF forecasts to 2021. Thereafter we adopt the 5-year average growth rates assumed in the EC Reference Scenario.

- For our **"High Growth Case"** we use the same assumptions but add 1% per year to the growth rate profile.

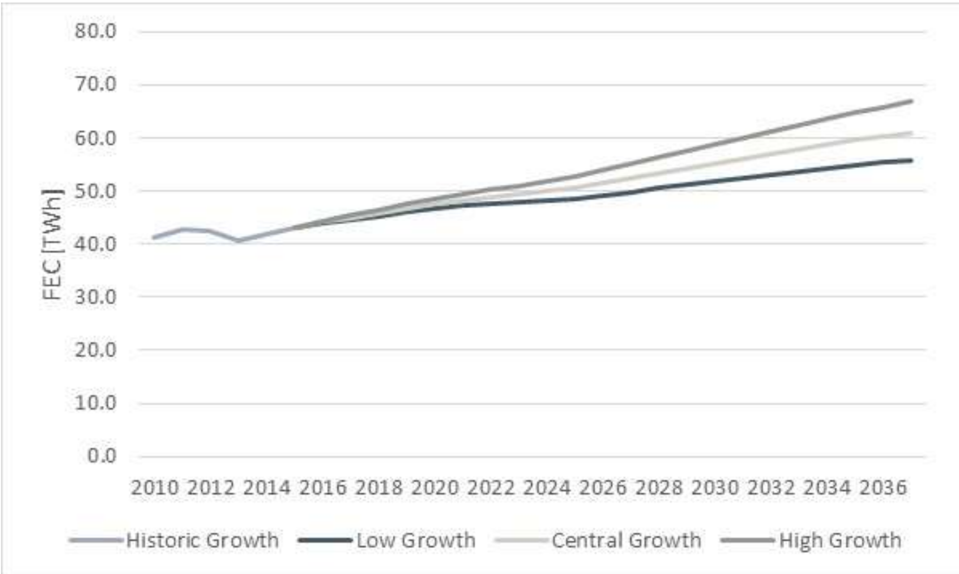
The share of FEC in final energy consumption is fixed to that used in the EC Reference Scenario which projects a gradual increase from 16.1% in 2015 to 17.8% in 2030. Figure 6 and Figure 7 present the three resulting demand projections for GFEC and FEC respectively.

Figure 6 Demand projections for GFEC



Source: ECA

Figure 7 Demand projections for FEC



Source: ECA

The sectoral breakdown of FEC is fixed to the shares provided in the Energy Balance of 2014. For the industrial sector, this includes the breakdown between "energy intensive industries" and "other industrial sub-sectors". The quantity of consumption for 2017 permitted to be exempt from the calculation of the GC obligation was estimated in the "Note for 2017" to be between 8 TWh and 9 TWh. We have therefore assumed a mid-point of 8.5 TWh, increased from 7.5 TWh in 2016. Thereon we have assumed the exempted quantity increases to 9 TWh where it is capped until the agreements expire in 2025.

For retail prices we have fixed the cost elements not attributable to either wholesale prices or the GC market (e.g. network tariffs, taxes, retail costs and margins) in real terms at the rate provided for 2015. In 2015 the network tariff for regulated consumers was 229.5 RON/MWh, while other costs were estimated to amount to 21.4 RON/MWh.

5.3 Baseline policy impact assessment

5.3.1 Treatment of policy variables

To establish the evolution of the GC market for our baseline projections we have attempted to set the policy variables to be unchanged from their current status/methodology with the following notes:

- The maximum and minimum GC prices remain constant in 2015 EUR terms.
- The deferment and reinsertion profiles are set to those provided for by Emergency Ordinance 57/2013. Namely that for GCs earnt by plant accredited by ANRE up to 31 December 2013:
    - From 1 July 2013 to 31 March 2017 the following certificates will temporarily deferred from trading:
        - 1 GC for new hydro plants under10 MW in capacity
        - 1 GC for wind power plants
        - 2 GCs for solar power plants
    - For hydro and solar plants the GCs will be reinstated at an even rate over the three year period 1 April 2017 to 31 March 2020.
    - For wind power plants the GCs will be reinstated at an even rate over the three year period 1 January 2018 to 31 December 2020.
- The validity of GCs lasts for 12 months.
- Law 220/2008 as amended stipulates that

  "The annual binding quotas of energy produced from renewable sources that benefits from the green certificates support system for 2020 – 2030 … should not be less than the quota established for 2020"

  The methodology for setting the quota described in Section 3 nevertheless caps the quota at the number of GCs issued (awarded plus reinserted) for that year. Due to the period of GC eligibility for many plant being set to end through the late 2020s this approach will reduce the quota below that established for 2020. As this capping is necessary to avoid an enforced shortfall of GC supply we adopt the current methodology in our baseline approach. Therefore the quota for 2021-2031 is capped to the lower of the 2020 quota and the number of GCs issued for that year.

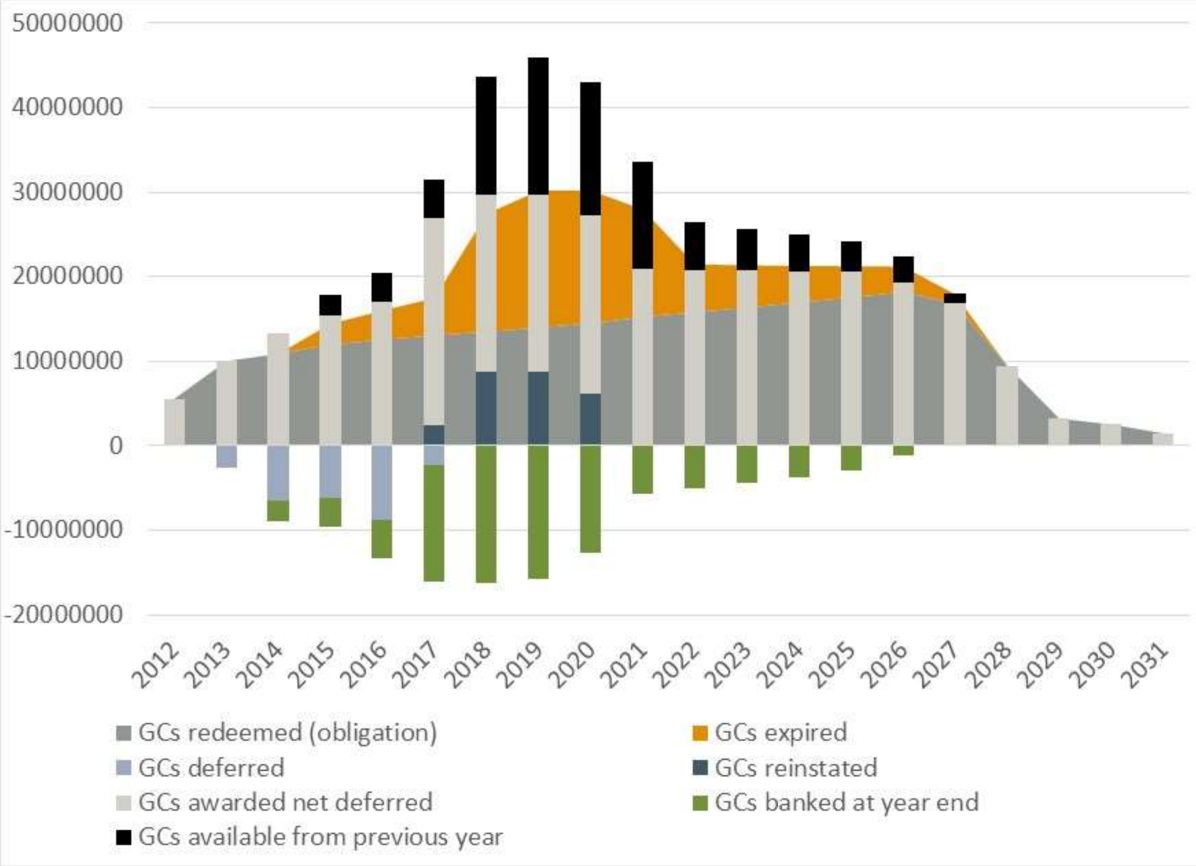
- The level of affordability deemed acceptable in 2016 (35 RON/GC) is adopted. However, we allow this value to rise in proportion to the projected increase in Romanian GDP per capita.

5.3.2 Baseline GC market projections

Under the above policy conditions our model shows that under all wholesale price-demand cases the RES-E quota to be met by the GC scheme drops sharply from 2026 as plant move beyond the period within which they are eligible for GC promotion.

Where the cases differ is in the point at which supply-demand balance is restored to the market. Under the central (Spark Spread plus Central GDP Growth) case our model shows the oversupply in certificates remains until 2028 albeit at a reduced level from 2021 when reinsertion of deferred GCs ceases. The status of certificates under this case is summarised in Figure 8 (and tabulated in Table 8). The stacked bars represent the supply of GCs for the given year – new GCs awarded (excluding any deferred), those which have maintained their validity from the previous year (i.e. are within their 12 months validity but were not redeemed) and those which have been reinserted. Negative bars indicate postponed GCs and GCs which were unsold and remain valid (ie can be banked) for the subsequent year. The stacked area shows the demand for GCs – the grey area being actual demand from the obligation (GCs to be redeemed) while the orange area represent demand shortfall – i.e. GCs which expire.

Figure 8 Status of GCs over time under baseline (central) projection



Source: ECA

Table 8 Status of GCs over time under baseline (central) projection (millions)

	'16	'17	'18	'19	'20	'21	'22	'23	'24	'25	'26	'27	'28	'29	'30	'31
Red-eemed	12.6	13.1	13.5	14.0	14.5	15.3	15.8	16.4	17.0	17.6	18.2	16.8	9.5	3.2	2.5	1.5
Expired	3.4	4.4	13.9	16.2	15.7	12.7	5.7	5.0	4.3	3.7	3.0	1.1	0.0	0.0	0.0	0.0
Deferred	8.8	2.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Re-instated	0.0	2.5	8.7	8.7	6.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Awarded net deferred	17.0	24.5	21.0	21.0	21.0	20.9	20.8	20.7	20.6	20.5	19.3	16.8	9.5	3.2	2.5	1.5
Banked	4.4	13.9	16.2	15.7	12.7	5.7	5.0	4.3	3.7	3.0	1.1	0.0	0.0	0.0	0.0	0.0
Avail-able from previous year	3.4	4.4	13.9	16.2	15.7	12.7	5.7	5.0	4.3	3.7	3.0	1.1	0.0	0.0	0.0	0.0

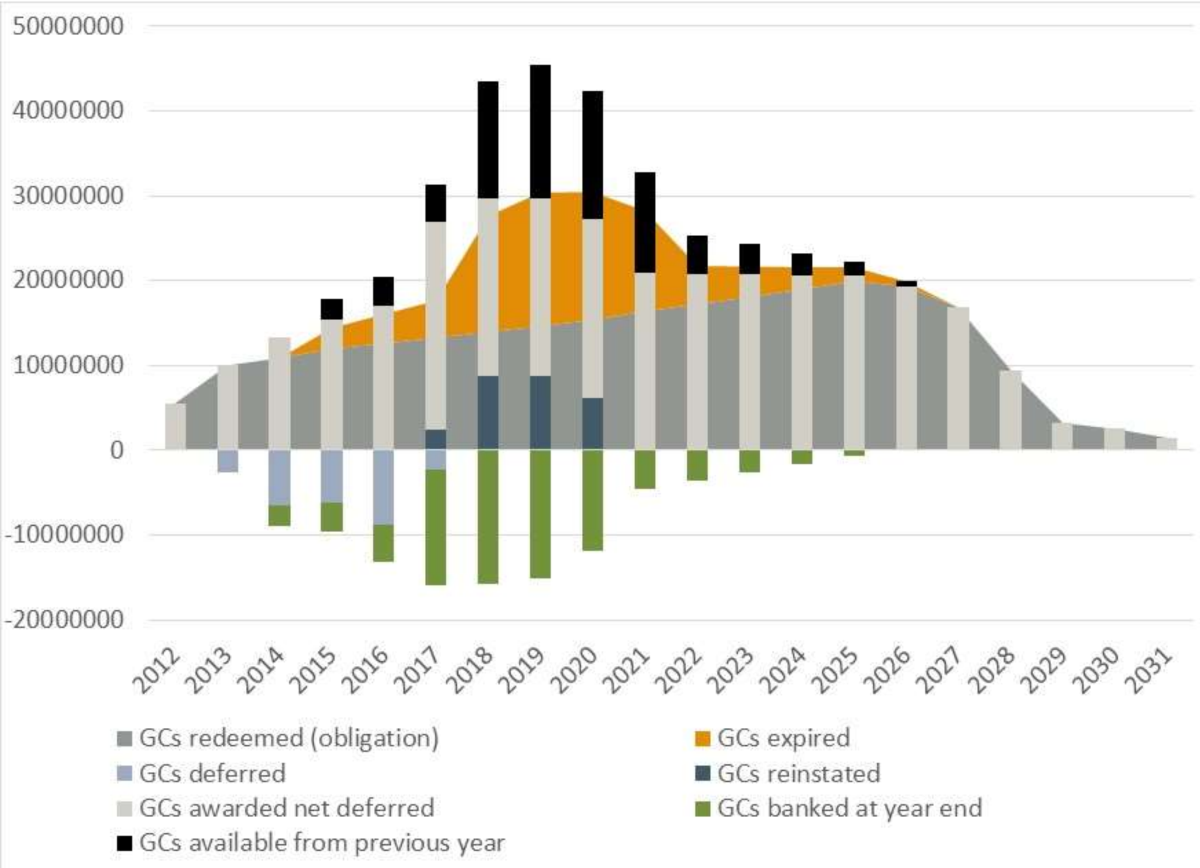
Source: ECA

Supply-demand balance is only regained in 2029 the GC price switches from the minimum price (where under this projection it stays until that date) to the maximum price. The national objective trajectory is met until 2020 after which it is not considered to affect the RES-E quota. If missed, under the current methodology the allowed impact can rise in negative proportion to the distance by which the target was missed. However, given no new supply can be accredited after 2016, increasing the allowed impact cannot bring forward any new RES-E production and hence has no effect on the market. Furthermore as the obligation methodology caps the GC obligation at the number of GCs estimated to be issued in that year, suppliers will not be liable for the shortfall via the penalty price.

Following the methodology of Order 101 2015, the above results calculate the capped RES-E quantity using the average GC price from the previous year. However, we note the methodology provides the option for ANRE to use a forecast price for the year that is different to the previous year should it deem it necessary. This creates a feedback effect as the price selected will define the quota which will in turn sets the price level.

A high-side sensitivity case using the High Commodities Price case for projecting wholesale power prices and High GDP Growth yields Figure 9 (and is tabulated in Table 9). In terms of allocation of GCs the outcome differs from the central projection with balance being initially restored to the market three years earlier in 2026/2027.

Figure 9 Status of GCs over time under Baseline (high) projection



Source: ECA

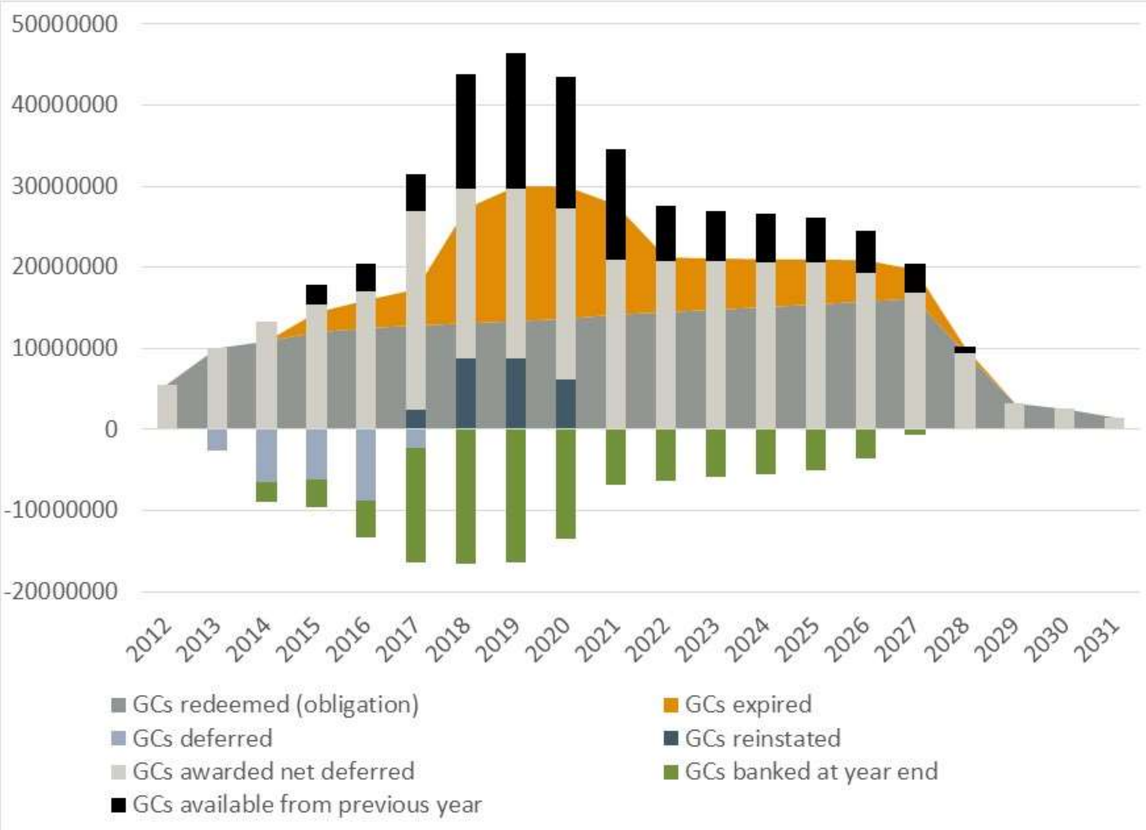
Table 9 Status of GCs over time under Baseline (high) projection (millions)

	'16	'17	'18	'19	'20	'21	'22	'23	'24	'25	'26	'27	'28	'29	'30	'31
Red-eemed	12.6	13.3	14.0	14.7	15.4	16.4	17.2	18.1	19.0	20.0	19.3	16.8	9.5	3.2	2.5	1.5
Expired	3.4	4.4	13.7	15.8	15.1	11.8	4.5	3.6	2.6	1.6	0.6	0.0	0.0	0.0	0.0	0.0
Deferred	8.8	2.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Re-instated	0.0	2.5	8.7	8.7	6.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Awarded net deferred	17.0	24.5	21.0	21.0	21.0	20.9	20.8	20.7	20.6	20.5	19.3	16.8	9.5	3.2	2.5	1.5
Banked	4.4	13.7	15.8	15.1	11.8	4.5	3.6	2.6	1.6	0.6	0.0	0.0	0.0	0.0	0.0	0.0
Avail-able from previous year	3.4	4.4	13.7	15.8	15.1	11.8	4.5	3.6	2.6	1.6	0.6	0.0	0.0	0.0	0.0	0.0

Source: ECA

Under the Low Commodities Price – Low Demand projection, supply-demand balance is achieved from 2030 with the price of certificates switches from the minimum to the maximum in that year.

Figure 10 Status of GCs over time under baseline (low) projection



Source: ECA

Table 10 Status of GCs over time under baseline (low) projection (millions)

	'16	'17	'18	'19	'20	'21	'22	'23	'24	'25	'26	'27	'28	'29	'30	'31
Red-eemed	12.5	12.8	13.1	13.4	13.7	14.2	14.5	14.8	15.1	15.4	15.8	16.2	9.5	3.2	2.5	1.5
Expired	3.4	4.5	14.1	16.6	16.3	13.6	6.8	6.3	5.9	5.5	5.1	3.5	0.7	0.0	0.0	0.0
Deferred	8.8	2.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Re-instated	0.0	2.5	8.7	8.7	6.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Awarded net deferred	17.0	24.5	21.0	21.0	21.0	20.9	20.8	20.7	20.6	20.5	19.3	16.8	9.5	3.2	2.5	1.5
Banked	4.5	14.1	16.6	16.3	13.6	6.8	6.3	5.9	5.5	5.1	3.5	0.7	0.0	0.0	0.0	0.0
Avail-able from previous year	3.4	4.5	14.1	16.6	16.3	13.6	6.8	6.3	5.9	5.5	5.1	3.5	0.7	0.0	0.0	0.0

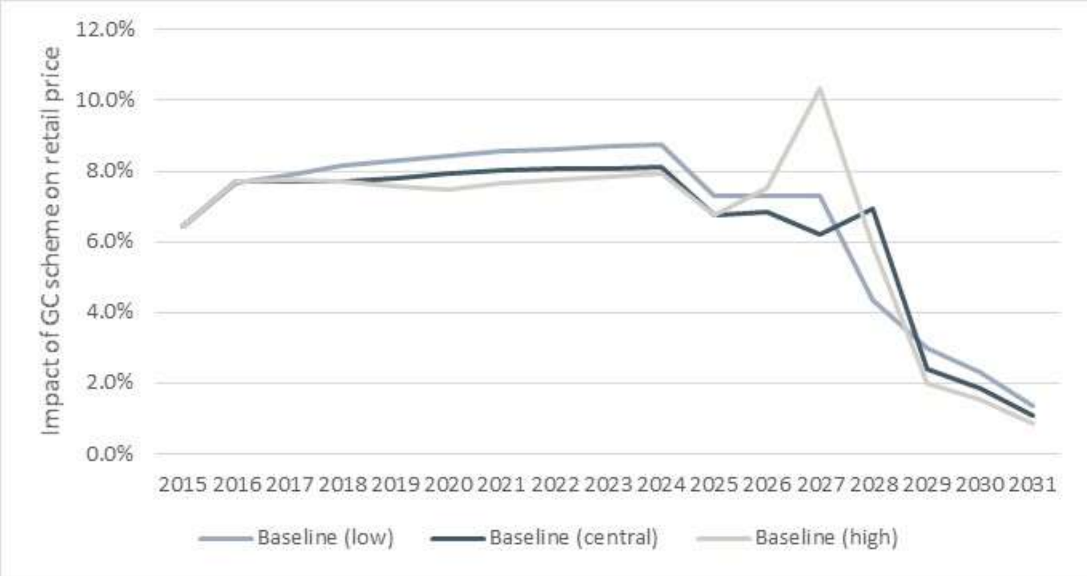
Source: ECA

5.3.3 Impact on final consumers

Households

Figure 11 summarises the impact of the GC scheme on the household electricity consumption bill. Prices correspond to between 6.4% and 8.7% of household bills under all projections with the exception of the years that oversupply is forecast to end and a spike is observed for the high case in 2027. The "spikes" are more diluted for the central and low cases by the general drop in scheme impact as plant eligibility expires. This is due to the aforementioned process of using the previous years' average GC price in setting the RES quota to be met with GCs. By setting the obligation based upon the minimum price (from the previous year) but then the price actually hitting the maximum, a temporary sharp uplift in tariff impacts is created until it can be mitigated for in the subsequent year by the pass-on of the higher average realised GC price. This effect could be potentially smoothed by using a forecast price rather than the previous years' price when setting the obligation.

Figure 11 Projected share of household tariff attributable to GC scheme



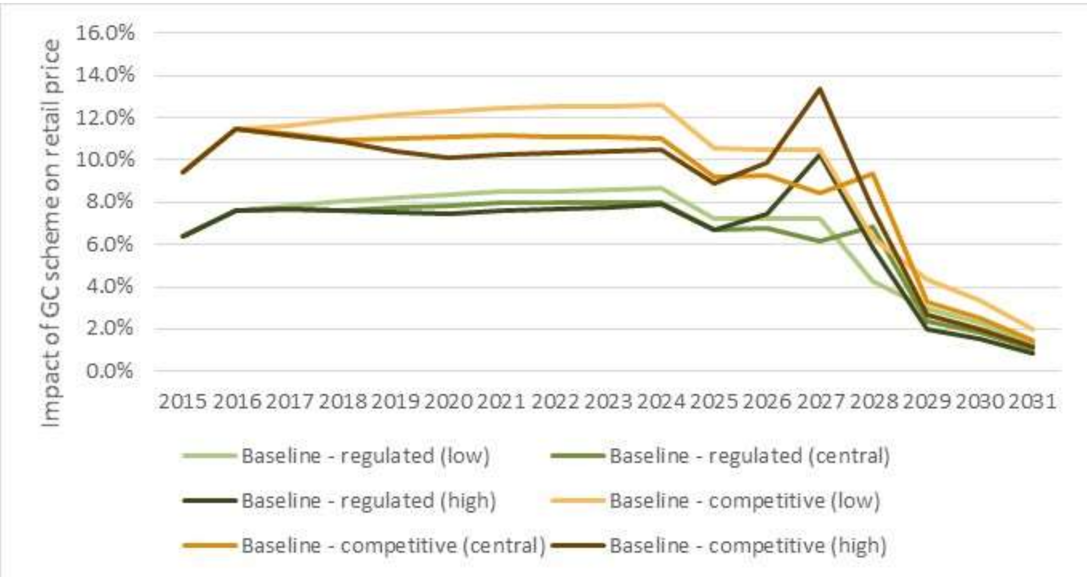
Source: ECA

As the GC obligation under this scenario is intrinsically limited by the affordability cap, it is no surprise that on average the consumer impact is constrained.

Non-households

Figure 12 shows the impact of the GCs scheme on tariffs for competitive and regulated non-household consumers in percentage terms. We again see a constrained impact across the timeframe: ~10-13% for competitive tariffs and ~7-9% for regulated tariffs. The exceptions are for 2026 in the high case where an oversupply is forecast, as previously seen in Figure 11, and a gradual reduction in the impact in later years due to a reduction in the quota.

Figure 12 Projected share of non-household tariff attributable to GC scheme



Source: ECA

5.3.4 Impact on RES-E producers

The impact on RES-E producers can be assessed both in aggregate and on the basis of those who successfully sell their GCs and those who fail to find a market (due to oversupply) and thus miss out disproportionately (in the extreme case, entirely). Bilateral (particularly long-term) purchase agreements for GCs will mean not all RES-E producers are capable of equal access to the GC market and thus where oversupply exists as at present (and in all our baseline projections to the late 2020s), a sub-set of producers will be disproportionately hit. These are more likely to be small independent players without established relationships to downstream retailers.

Nevertheless, there remains use in looking at the RES-E producer average impact per technology. In the case the average impact is considered appropriate, a reduction in the minimum trading price - which raises the GC obligation under a constant allowed consumer impact) - can be made to the point oversupply is sufficiently small that all GCs could be expected to be purchased. Alternatively a pooling mechanism could be adopted which socialises the lack of demand across all producers evenly by trading through a central aggregator.

Table 11 summarises the calculated baseline modified IRRs[9] (MIRR) for the four main technology forms for each year of accreditation (assumed to be the same as the year of installation) under each price-demand projection. The results indicate that wind and biomass CHP[10] plant have very low returns, under 3% in real terms for the low case and (with the exception of 2016 biomass CHP) under 5% real even in the central case. Solar and to a lesser extent new hydro show stronger results, but only certain years and scenarios exceed the targeted 10% IRR (8.2% real).

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[9] The modified IRR (MIRR) is used due to fluctuating cash flows meaning a unique IRR solution is not applicable in all cases. The borrowing rate for negative cash flows is set at 5.25% real while the reinvestment rate for positive cash flows is set at 8.2% real (ie the target above which overcompensation is declared)

[10] In calculating biomass CHP returns we have assumed a heat to power output ratio of 2:1 and a heat revenue of 91 RON/MWh based on ANRE Order 152/14.10.2015. The true ratio may vary widely and thus results are best used for comparing the relative MIRR estimates under the various scenarios rather than in absolute terms.

Table 11 RES-E generator estimated Modified IRRs (real terms)

	Average Modified IRR (%) for RES-E capacity by year of accreditation					
	2011	2012	2013	2014	2015	2016
Baseline (low)						
Wind	2.4	2.4	1.7	1.3	2.2	-
New hydro	3.8	4.5	4.9	-	6.2	-
Biomass CHP	1.8	1.2	-0.1	0.0	1.0	2.0
Solar PV	4.1	4.7	6.7	4.7	5.4	7.7
Baseline (central)						
Wind	3.5	3.6	3.4	3.2	4.2	-
New hydro	4.5	5.2	5.8	-	7.3	-
Biomass CHP	3.2	3.0	2.8	3.5	4.3	5.4
Solar PV	4.7	5.3	7.5	5.9	6.6	8.8
Baseline (high)						
Wind	4.2	4.6	4.6	4.5	5.6	-
New hydro	5.0	5.9	6.6	-	8.2	-
Biomass CHP	4.3	4.5	4.9	5.6	6.5	7.5
Solar PV	5.2	5.9	8.4	6.8	7.5	9.7

Source: ECA

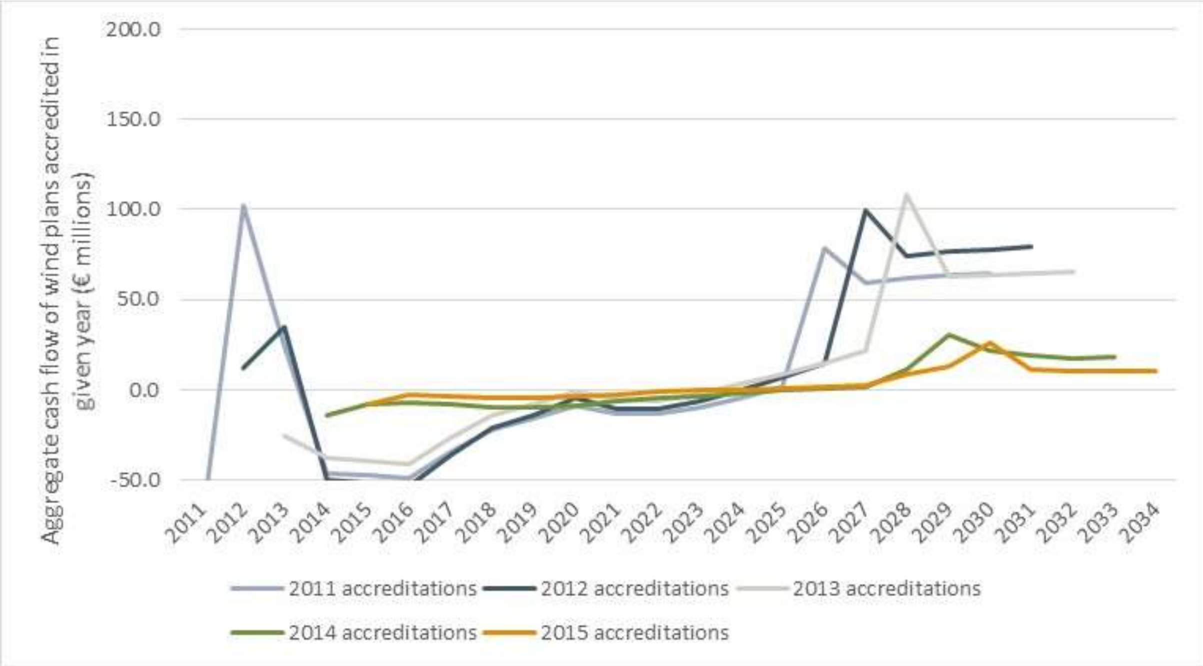
However, even under the high wholesale price and high demand projection (baseline high), plants which cannot sell their GCs (due to the oversupply) and are therefore 100% reliant on the wholesale power price, would not achieve a 5% or greater MIRR for any technology, less than 2% in most cases and substantially negative for biomass CHP.

The results in Table 11 may further flatter the MIRRs for some independent wind and solar plants that are unable to enter balancing centre agreements. If such sites incur balancing costs on a site-by-site basis, their MIRRs fall. Under the baseline (central) scenario this equates to a drop in the MIRR for wind plant in the order of 0.5% for all year groups.

Only 2% of wind capacity relates to plants which are not designated as dispatching units and thus exempt from the costs incurred through both capping GCs by the notified value and balancing market prices. However, 55% of solar capacity is located in plant below the 5 MW threshold. The figures presented in Table 11 are average returns across both dispatching and non-dispatching units. Those solar plants subject to balancing costs may therefore see slightly lower MIRRs than presented even when entered into a balancing centre agreement.

A further issue arises from cash flow. Oversupply is highest during the early years of the study and GC market prices rise only towards the very end of the scheme period. Debt servicing for a RES-E producer, meanwhile, will be concentrated in the early years of operation. To illustrate we have assumed a project financing arrangement with a 70% loan repaid over the first fifteen years of operation at a real terms interest rate of 5.25% for all technologies. Figure 13 illustrates a simplified cash flow for wind power plants accredited in each year 2011 to 2015 inclusive of the debt service assumptions under the baseline (central) case. As can be seen, under the central baseline case returns are estimated to be insufficient to cover debt service and operational expenditure until the mid-2020s for all year groups.

Figure 13 Cash flow estimation for wind power plants



Source: ECA

6 Scenarios

This section builds upon the baseline projections by varying the key policy inputs. For each policy scenario we report on the expected profile of the GC market, the impact on consumer bills and the impact on RES generation revenue as well as cash flow. The four policy variables we investigate are:

- The methodology for setting the GC quota and its level
- Varying the rate for the planned reinsertion of previously deferred GCs
- Varying the maximum and minimum (cap and floor) prices for GCs
- Varying the period of validity ("banking") of GCs from year-to-year

6.1 Variation in GC quotas

The current methodology for setting the GC quota is based upon the national RES objectives set by transposition of Directive 2009/28/EC. While capped by the number of GCs issued (awarded plus reinserted) in a given year, this means that in a surplus situation the size of the obligation has no relationship with the level of GC supply expected within a given year. Targets for RES-E are affected by slower or quicker than expected progress on RES use in heat and transport and overall demand for electricity. Furthermore the targets set in the directive only apply until end 2020 after which the only criteria is that the quota be not less than that for 2020.

As described in Section 2, the demand curve for a certificate mechanism such as the GC scheme in Romania is near vertical, while no new supply is now capable of responding to price signals and enter the market as the scheme is closed to new entrants. Given these characteristics and the previous reduction in the obligation quota, it would be highly coincidental if supply and demand *were* to be in balance.

In this sub-section we therefore investigate two alternative obligation profiles/approaches:

- **"Targeted Obligation"**. We model an alternative case where the obligation is set endogenously within the model as a function of the expected supply of certificates. In this scenario the obligation is first set at a level 5% higher than the actual expected number of GCs issued in that year (inclusive of any reinsertions). Based on our assumed demand curve this would cause sufficient oversupply for the price to just reach the minimum regulated level but not for significant numbers of GCs to remain unsold. A sensitivity check with a margin of 10% is also presented.
- **"Static Obligation"**. We model one further case in which we try to keep the impact of the GCs as even as possible across the life of the scheme up to 2031. Given this scenario implies that the impact of GCs does not "tail down" at the end of the scheme, it requires that GCs remain eligible for reinsertion after RES

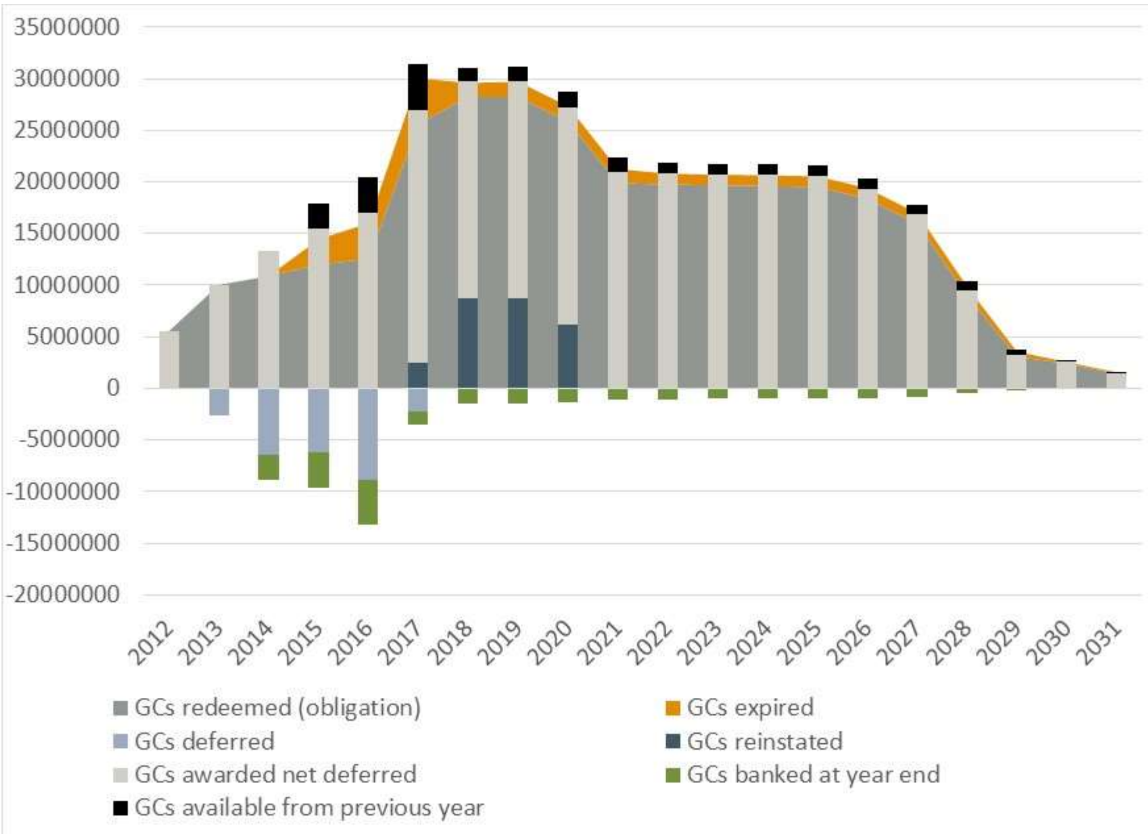
plants have stopped earning GCs, i.e. GCs are modelled as having indefinite validity to avoid impact spikes.

6.1.1 Targeted obligation

The only way to ensure supply and demand of GCs achieves reasonable balance in a market where supply is fixed is to purposefully target demand (i.e. the obligation) to meet or be similar to expected supply. In this case we assume a small oversupply of GCs in line with an expected "safety margin" for purchase by suppliers of 5%. This would likely be sufficient to see trading take place at the minimum price but few GCs to be left unsold.

Figure 14 (tabulated in Table 12) shows the projected status of the GC market under this scenario while Figure 15 presents the projected impact on consumers as compared to the baseline (central) projection. The charts show that due to the significant "bulge" of GCs available for trading during 2017-2020 when previously deferred GCs get reinstated, in order to prevent oversupply in these years the impact on consumer tariffs (all else being the same) would similarly have to allow for a short-term elevation.

Figure 14 GC market projection for "targeted obligation" scenario



Source: ECA

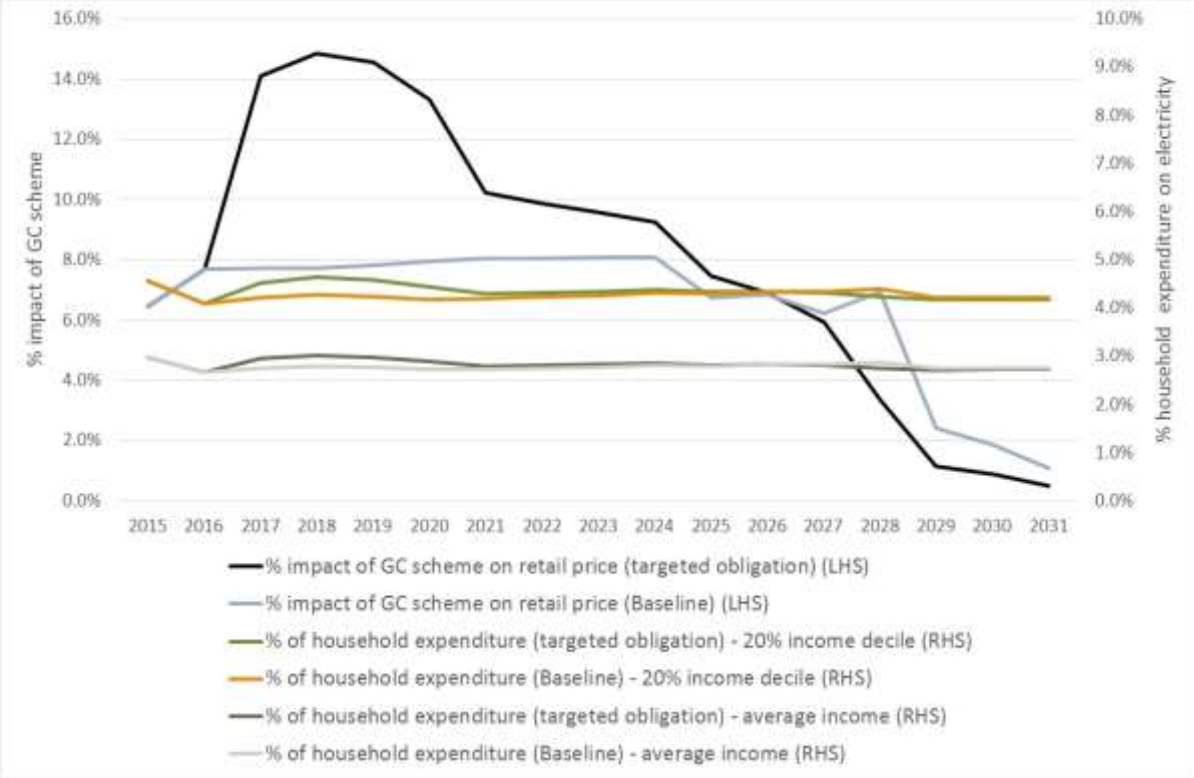
Table 12 GC market projection for "targeted obligation" (millions)

	'16	'17	'18	'19	'20	'21	'22	'23	'24	'25	'26	'27	'28	'29	'30	'31
Red-eemed	12.6	25.6	28.2	28.2	25.9	19.9	19.8	19.7	19.6	19.5	18.4	16.0	9.0	3.1	2.4	1.4
Expired	3.4	4.4	1.3	1.5	1.5	1.4	1.0	1.0	1.0	1.0	1.0	1.0	0.8	0.5	0.2	0.1
Deferred	8.8	2.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Re-instated	0.0	2.5	8.7	8.7	6.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Awarded net deferred	17.0	24.5	21.0	21.0	21.0	20.9	20.8	20.7	20.6	20.5	19.3	16.8	9.5	3.2	2.5	1.5
Banked	4.4	1.3	1.5	1.5	1.4	1.0	1.0	1.0	1.0	1.0	1.0	0.8	0.5	0.2	0.1	0.1
Avail-able from previous year	3.4	4.4	1.3	1.5	1.5	1.4	1.0	1.0	1.0	1.0	1.0	1.0	0.8	0.5	0.2	0.1

Source: ECA

As seen in Figure 15, the GC scheme's impact on household tariffs briefly rises to around 15% in 2018 from under 6.5% in 2015. However, electricity costs as a percentage of total expenditure are forecast to peak at 4.6% for households at the 20% income decile and 3.0% for average income households – the same values as in 2015. This is due to the fall in power prices in 2016 lowering overall expenditure on electricity in the peak impact years and compensating for the rise in GC scheme impact.

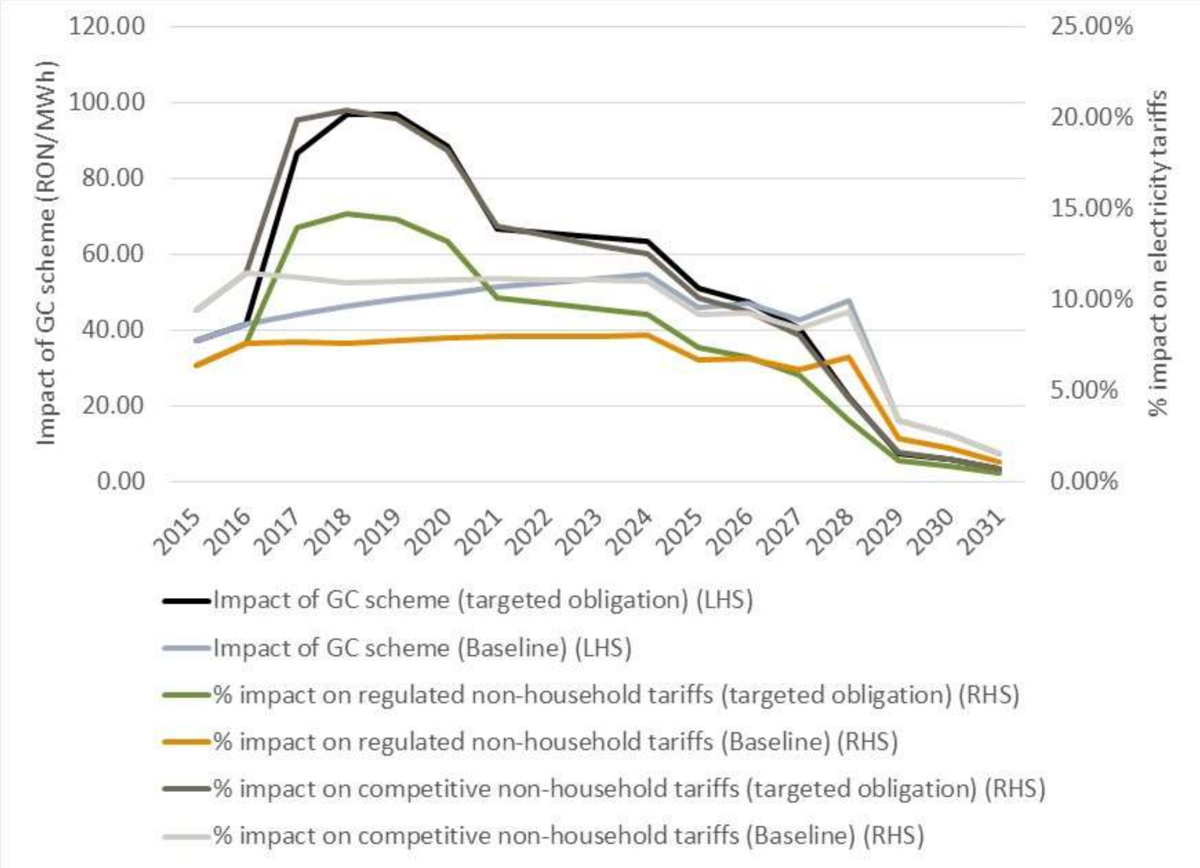
Figure 15 Impact on household consumers of "targeted obligation" scenario



Source: ECA

The initial impact on non-household consumers is even more pronounced in Figure 18 for competitive non-household tariffs where they are estimated to reach over 20% of the tariff in 2018. Non-household regulated tariffs are at a similar level to that for households and hence also peak at around 15%.

Figure 16 Impact on non-household consumers of "targeted obligation" scenario



Source: ECA

The impact for RES-E producers of moving towards such a methodology with no other changes is unsurprisingly positive compared to current policies with all technology forms for all years estimated to achieve real MIRRs of at least 4% (Table 13), with 2014 wind the exception. Nevertheless returns for most technology-year groups remain low compared to the 8.2% benchmark.

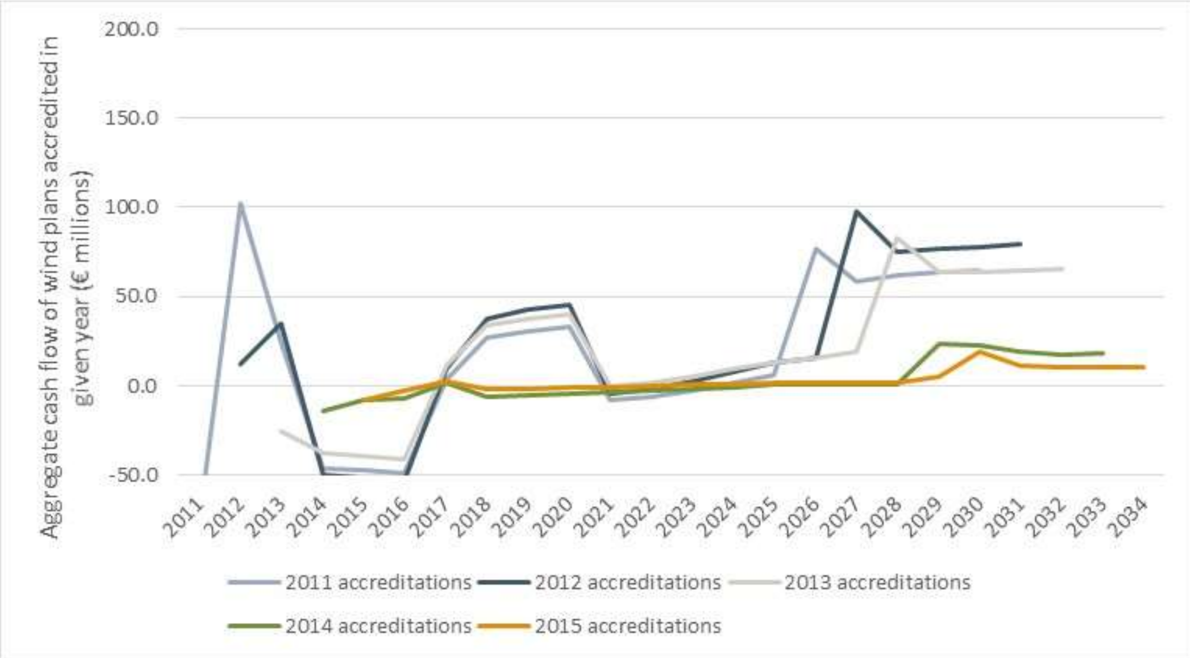
Table 13 RES-E generator estimated Modified IRRs (real terms) under "targeted obligation" scenario with 5% surplus

	Average real Modified IRR (%) for RES-E capacity by year of accreditation					
	2011	**2012**	**2013**	**2014**	**2015**	**2016**
Baseline (central)						
Wind	4.1	4.3	4.1	3.5	4.3	-
New hydro	5.3	6.1	6.6	-	7.5	-
Biomass CHP	4.4	4.3	4.3	4.4	4.9	5.6
Solar PV	5.8	6.4	8.5	6.4	6.8	8.8

Source: ECA

Cash flows under this scenario turn positive from 2017 for all technology groups accredited - during 2011-2013 bar biomass CHP for 2011 and 2012 which did not have GCs deferred and hence does not receive the revenue boost as they are reinserted. However, once the reinsertion has ended cash flows turn once negative in the early 2020s before rising power prices bring a return to positive levels prior to debt service obligations ending. This pattern for wind plant is presented in Figure 17.

Figure 17 Cash flow estimation for wind power plants under "targeted obligation"



Source: ECA

Sensitivity Case with 10% surplus

We have undertaken a sensitivity case on the "targeted obligation" scenario using a targeted surplus of 10% as opposed to 5% but with the same demand curve assumptions as previously.

The projected GC market profile that results is similar to that presented in Figure 14 except with a broader band of expired GCs each year (the surplus). This has the result of reducing the consumer impact with respect to the 5% surplus case to a peak of 14.2% of the household tariff, 14.0% of the regulated non-household tariff and 19.6% of the non-household competitive tariff. The lower quota size inevitably also reduces RES-E producer MIRRs slightly as shown in Table 14 and marginally harms cash flows.

Table 14 RES-E generator estimated Modified IRRs (real terms) under "targeted obligation" scenario with 10% surplus

	Average Modified IRR (%) for RES-E capacity by year of accreditation					
	2011	**2012**	**2013**	**2014**	**2015**	**2016**
Central						
Wind	4.0	4.2	4.0	3.4	4.2	-
New hydro	5.2	5.9	6.5	-	7.3	-
Biomass CHP	4.2	4.1	4.0	4.1	4.5	5.2
Solar PV	5.6	6.2	8.3	6.2	6.6	8.5

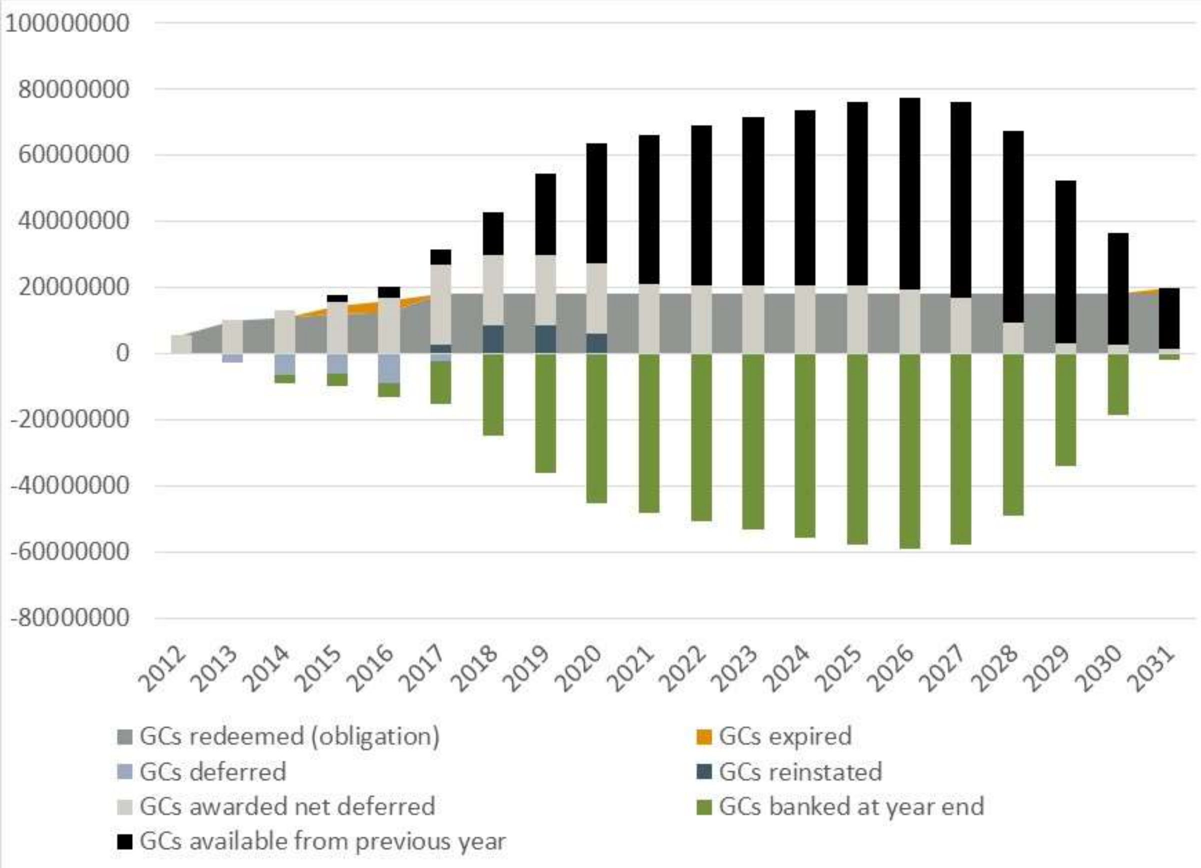
Source: ECA

6.1.2 Static obligation

The "static obligation" scenario presents the case where spreading the impact of the GC scheme evenly across the whole timeframe was the primary goal. Under this option, the validity of GCs is indefinite, allowing RES plants to sell GCs beyond the period in which they earn GCs, which balances both the benefit to RES plants and the impact on consumers.

Figure 18 shows how this leads to extended period of heavy banking of GCs by RES plants across the timeframe as GCs are redeemed at an even pace rather than bunched in the early phase of the timeframe. The overhang of surplus GCs from 2016 runs through the whole time series to remain unsold at the end of the scheme. This surplus is estimated to be sufficient to prevent prices from rising to the maximum in the final year.

Figure 18 GC market projection for "static obligation" scenario



Source: ECA

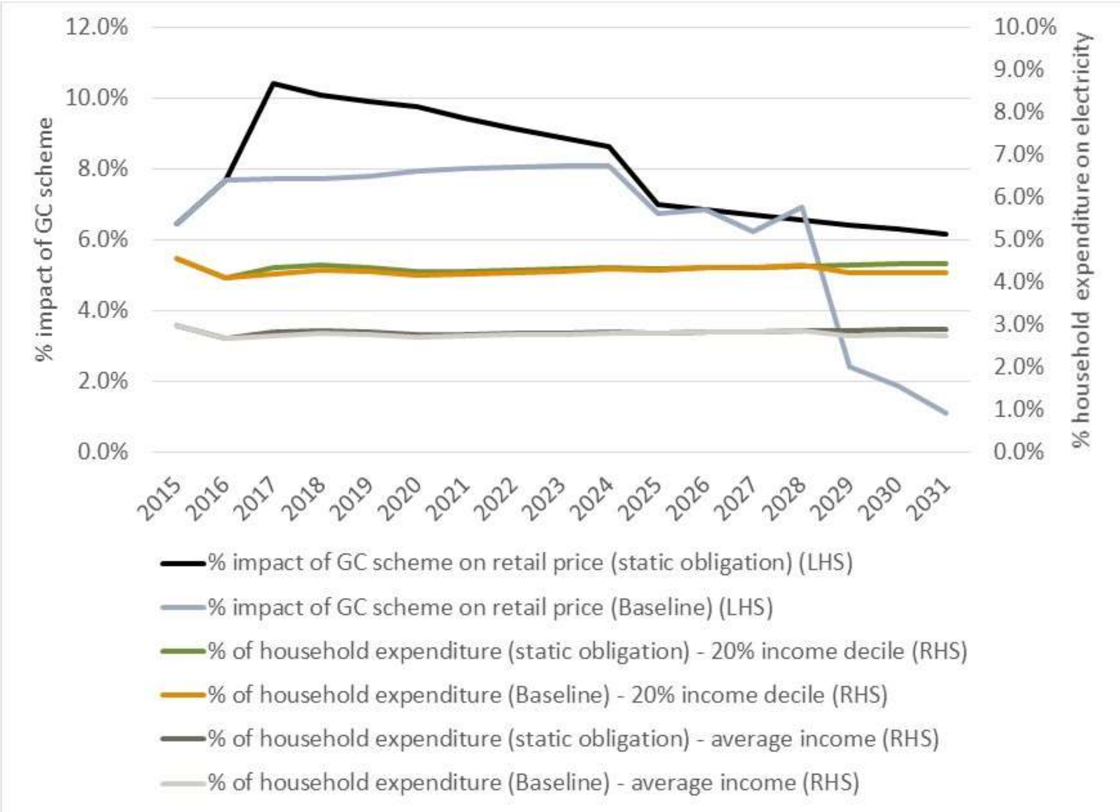
Table 15 GC market projection for "static obligation" (millions)

	'16	'17	'18	'19	'20	'21	'22	'23	'24	'25	'26	'27	'28	'29	'30	'31
Red-eemed	12.6	18.2	18.2	18.2	18.2	18.2	18.2	18.2	18.2	18.2	18.2	18.2	18.2	18.2	18.2	18.2
Expired	3.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.8
Deferred	8.8	2.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Re-instated	0.0	2.5	8.7	8.7	6.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Awarded net deferred	17.0	24.5	21.0	21.0	21.0	20.9	20.8	20.7	20.6	20.5	19.3	16.8	9.5	3.2	2.5	1.5
Banked	4.4	13.2	24.8	36.3	45.3	48.1	50.7	53.2	55.6	58.0	59.1	57.8	49.1	34.1	18.5	1.8
Avail-able from previous year	3.4	4.4	13.2	24.8	36.3	45.3	48.1	50.7	53.2	55.6	58.0	59.1	57.8	49.1	34.1	18.5

Source: ECA

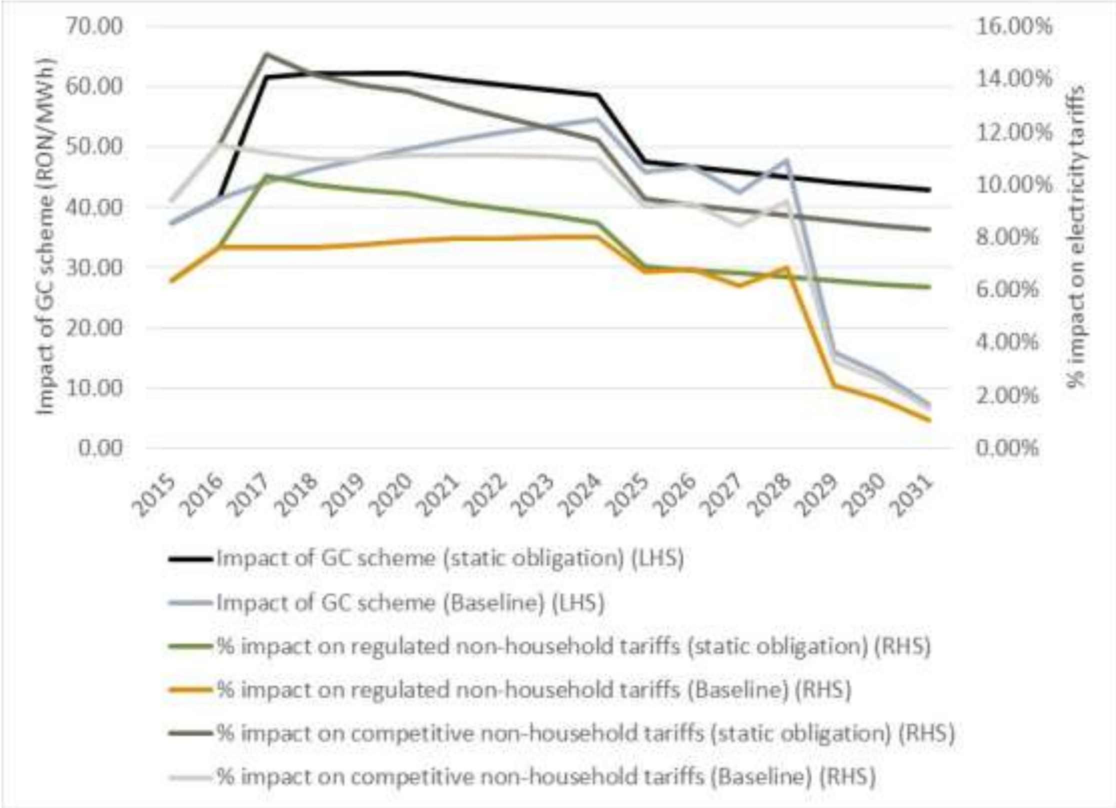
In terms of the impact on consumers, Figure 19 and Figure 20 show a more immediate impact on tariffs that gradually declines, rather than the gradual increase under the current policy regime. The overall impact over the whole timeframe is also larger as more GCs are redeemed in total. The step down in 2025 is due to the expiry of the exemptions provided to energy-intensive users helping to spread the impact over a wider FEC.

Figure 19 Impact on household consumers of "static obligation" scenario



Source: ECA

Figure 20 Impact on non-household consumers of "static obligation" scenario



Source: ECA

As it targets the sale of almost all GCs this policy gives similar returns to the targeted obligation case, reduced slightly for early plant as returns are comparatively delayed (and hence valued at a greater discount) and raised slightly for latter plant due to the smaller surplus of GCs targeted (Table 16).

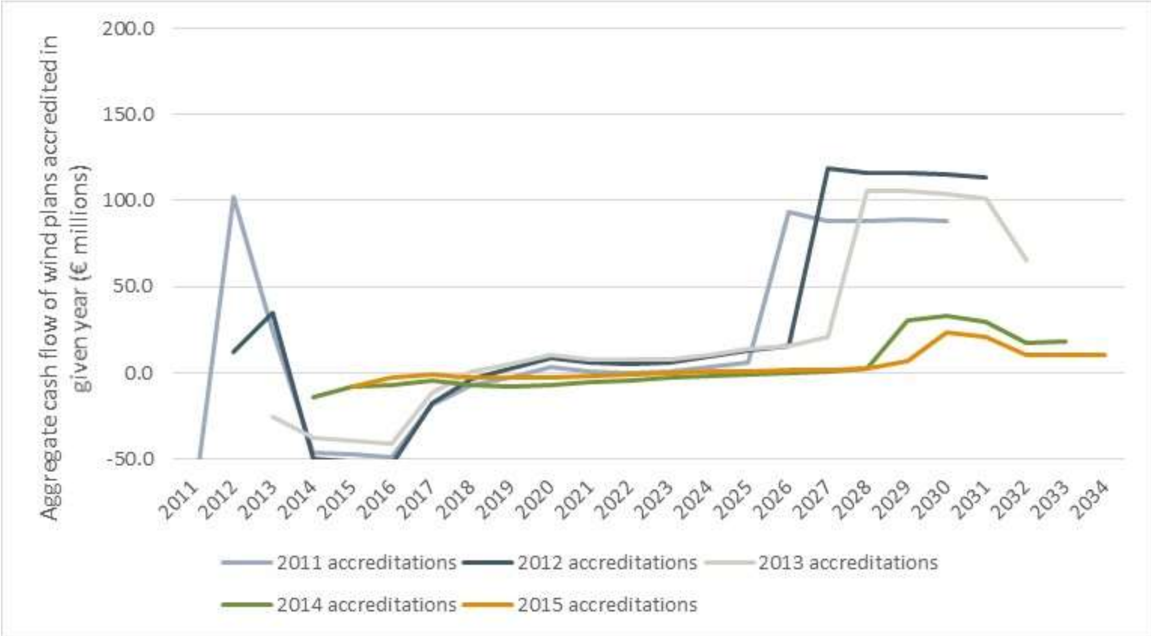
Table 16 RES-E generator estimated Modified IRRs (real terms) under "static obligation" scenario

	Average Modified IRR (%)for RES-E capacity by year of accreditation					
	2011	**2012**	**2013**	**2014**	**2015**	**2016**
Central						
Wind	4.1	4.3	4.1	3.5	4.3	-
New hydro	5.2	6.0	6.5	-	7.5	-
Biomass CHP	4.2	4.1	4.1	4.4	4.9	5.6
Solar PV	5.7	6.2	8.4	6.3	6.7	8.7

Source: ECA

Cash flows under this scenario are less volatile than under the targeted obligation approach becoming positive for 2011-2013 wind plant during 2018-2020. Wind plant accredited in 2014 and 2015, however, do not see positive cash flows until the mid-2020s as a result of the banking of surplus GCs required in early years to meet the obligation in later years (Figure 21).

Figure 21 Cash flow estimation for wind power plants under "static obligation"



6.2 Variation in reinsertion rate

The struggle between establishing a manageable cash flow in the years to 2020 while also keeping the scheme affordable is in a large part the result of the reinsertion of the previously deferred GCs in the years 2017-2020. This creates a bulge in availability of GCs forcing either a high number of expiring GCs, a very low minimum price or accepting a high target and consumer impact.

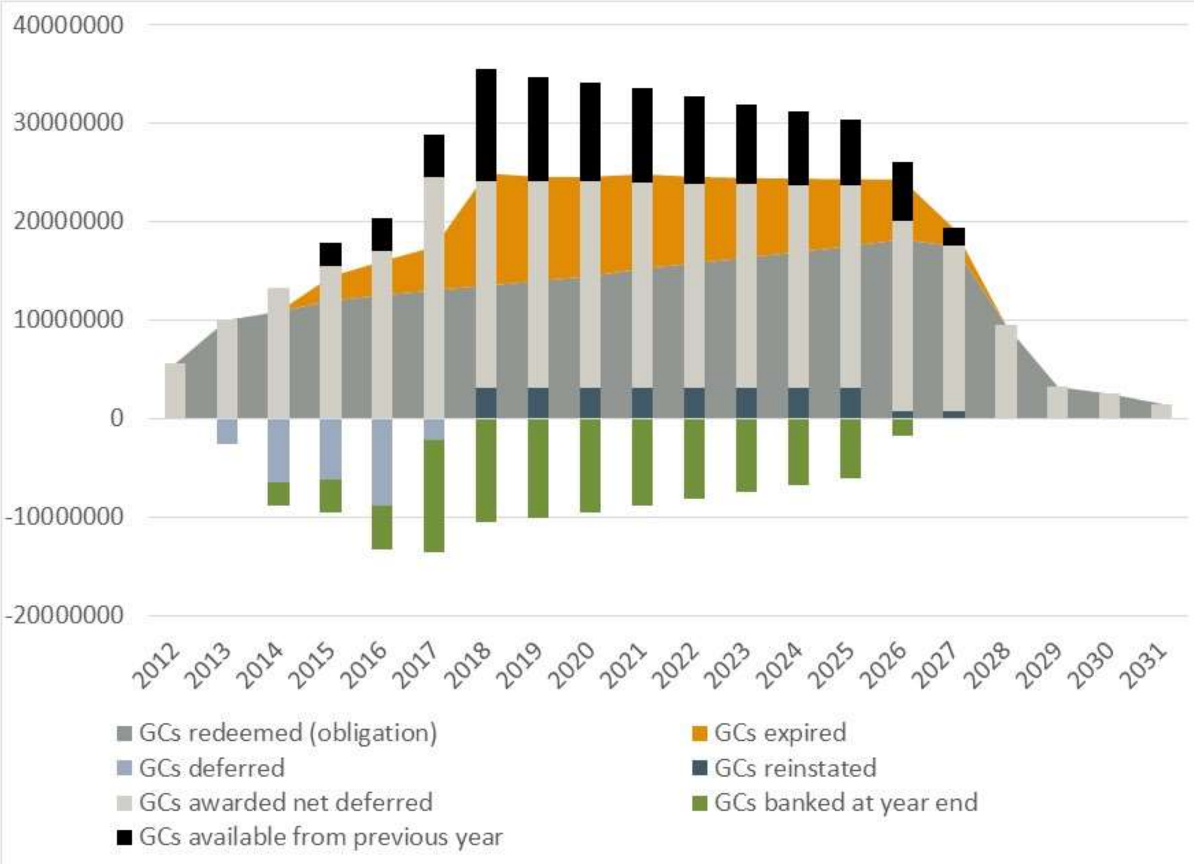
In this section we look at the impact of varying the reinsertion rates from those currently defined.

We have analysed spreading the reinsertion of the postponed GCs to be over an eight year period for wind and hydro plants and ten years for solar plants, starting from 2018 for all three technologies.

6.2.1 Slowing reinsertion rate with the current obligation methodology

With no other changes and maintaining the current methodology for setting the quota obligation, the main effect of slowing reinsertion is the smoothing of the rate of GCs expiring, as shown in Figure 22**Error! Reference source not found.**. However, with only a slight increase in the MIRRs for pre-2014 RES producers (at the expense of post-2014 RES producers), this also causes a larger overall impact on consumers by raising the impact of the later years of the scheme. The change is also insufficient to mitigate for the cash flow constraints which remain highly negative prior to 2020 and do not turn positive until the mid-2020s.

Figure 22 GC market with extended GC reinsertion rate



Source: ECA

Table 17 GC market with extended GC reinsertion rate

	'16	'17	'18	'19	'20	'21	'22	'23	'24	'25	'26	'27	'28	'29	'30	'31
Red-eemed	12.6	13.1	13.5	14.0	14.5	15.3	15.8	16.4	17.0	17.6	18.2	17.5	9.5	3.2	2.5	1.5
Expired	3.4	4.4	11.4	10.6	10.1	9.6	8.8	8.1	7.4	6.8	6.1	1.8	0.0	0.0	0.0	0.0
Deferred	8.8	2.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Re-instated	0.0	0.0	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	0.7	0.7	0.0	0.0	0.0	0.0
Awarded net deferred	17.0	24.5	21.0	21.0	21.0	20.9	20.8	20.7	20.6	20.5	19.3	16.8	9.5	3.2	2.5	1.5
Banked	4.4	11.4	10.6	10.1	9.6	8.8	8.1	7.4	6.8	6.1	1.8	0.0	0.0	0.0	0.0	0.0
Avail-able from previous year	3.4	4.4	11.4	10.6	10.1	9.6	8.8	8.1	7.4	6.8	6.1	1.8	0.0	0.0	0.0	0.0

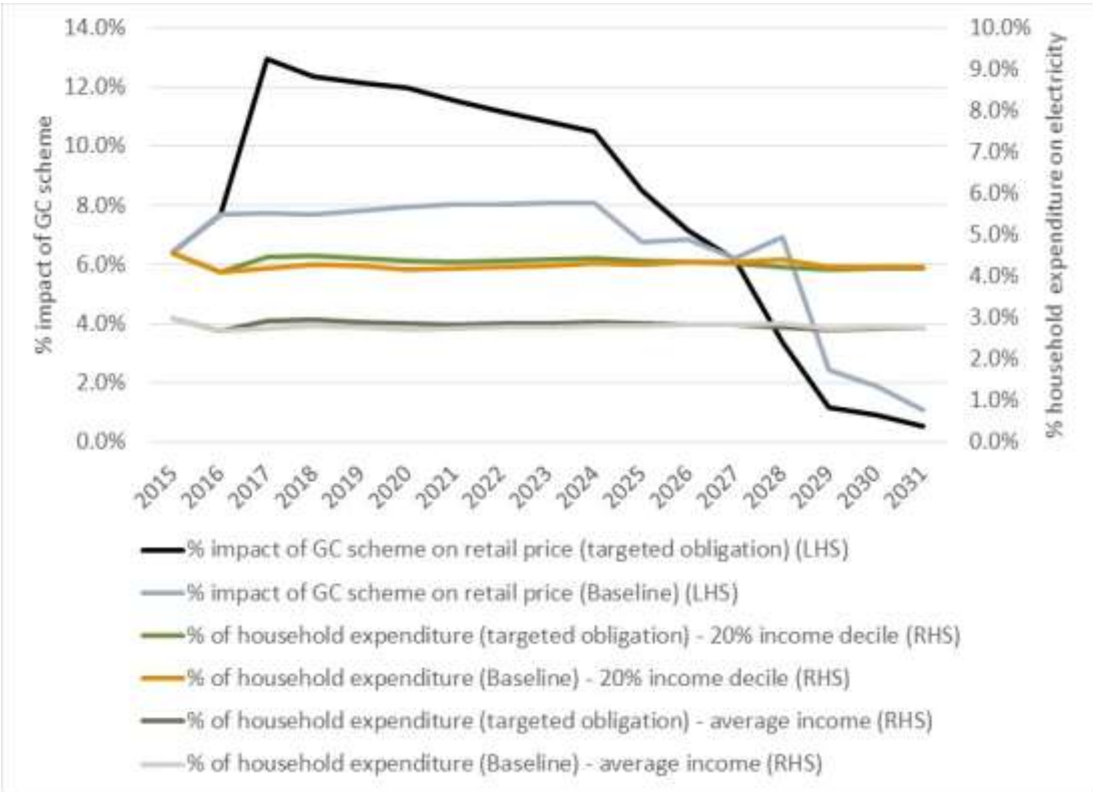
Source: ECA

6.2.2 Slowing reinsertion rate in the "targeted obligation" scenario

Under the "targeted obligation" scenario reinserting across 10 years for solar and 8 years for wind and hydro contributes to the smoothing of the profile. As a result this also smooths the "bulge" in the impact on households' and non-households' percentage of expenditure on electricity observed for 2017-2020 in Section 6.1.1 across a longer timeframe, as shown in Figure 23**Error! Reference source not found.** and Figure 24**Error! Reference source not found.**.

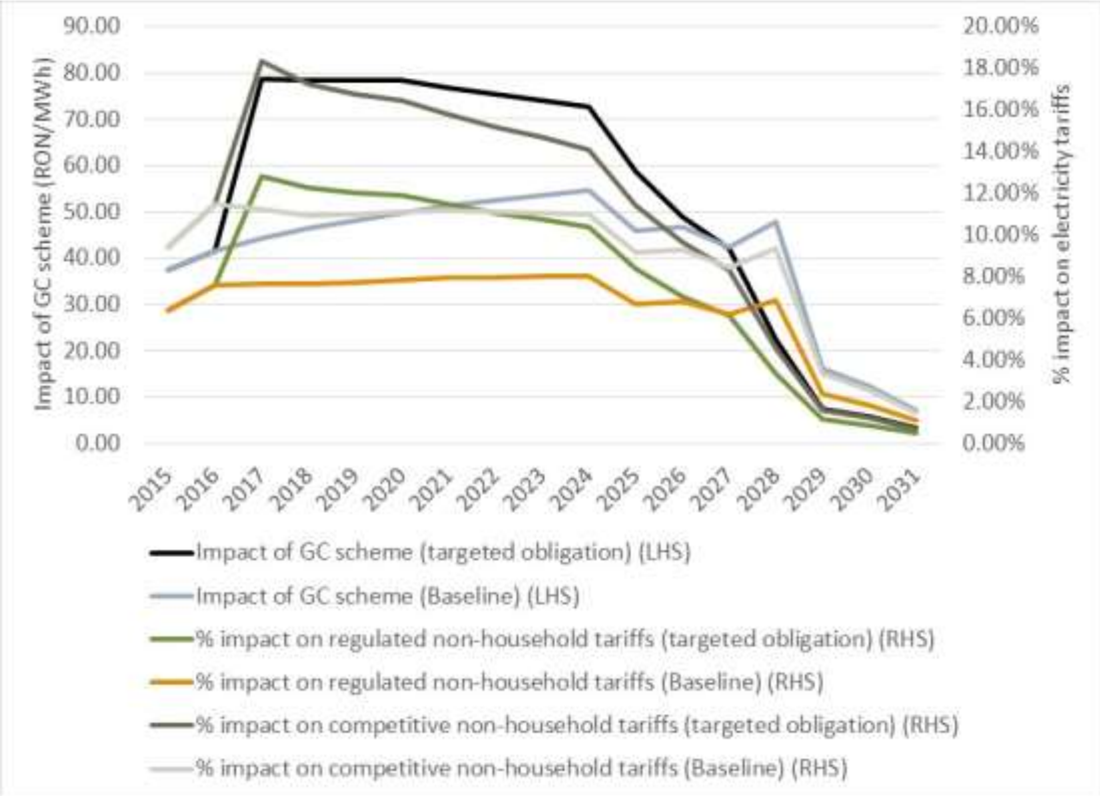
Cash flow is also substantially improved (Figure 25**Error! Reference source not found.**) for the large majority of RES-E producers from 2017 – the first year of implementation. 2014 and 2015 wind accreditations still struggle to make a positive return until the mid-2020s although these plant represent less than 12% of wind capacity. However, the overall impact on consumers remains higher than in the baseline (central) case. Returns for RES-E producers are largely the same as without extended reinsertion under the "targeted obligation" scenario (Table 18).

Figure 23 Impact on households under targeted obligation and extended reinsertion rate



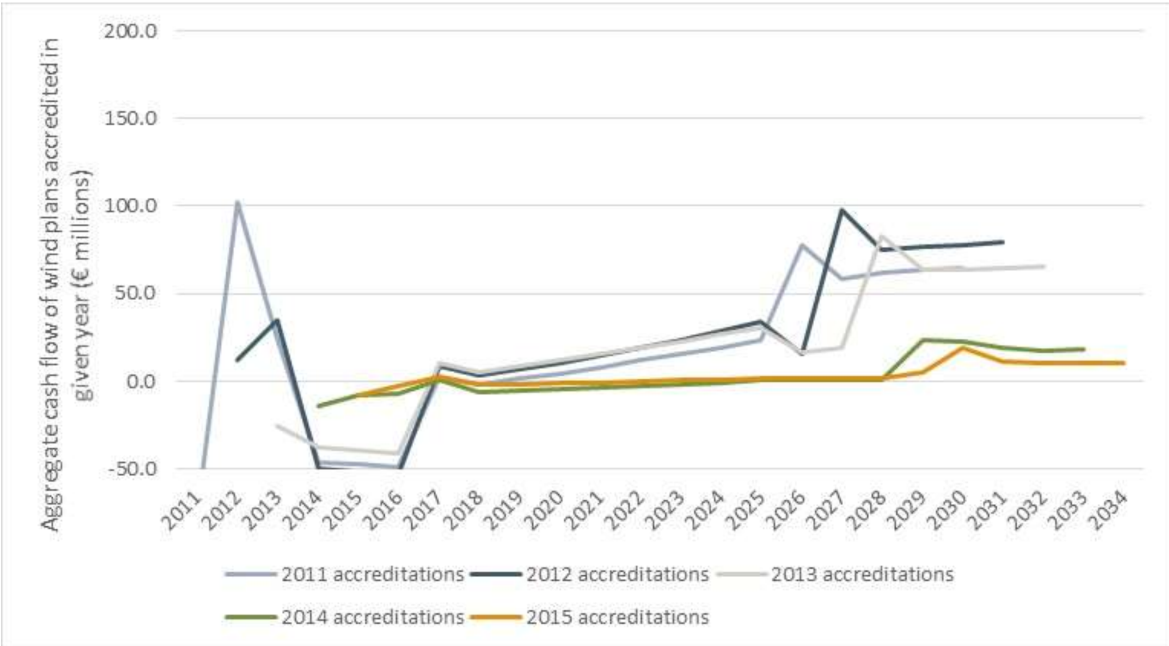
Source: ECA

Figure 24 Impact on non-households under targeted obligation and extended reinsertion rate



Source: ECA

Figure 25 Cash flow forecast with extended GC reinsertion rate and targeted obligation



Source: ECA

Table 18 RES-E generator estimated Modified IRRs (real terms) with extended GC reinsertion rate and targeted obligation

	Average Modified IRR (%) for RES-E capacity by year of accreditation					
	2011	2012	2013	2014	2015	2016
Central						
Wind	4.1	4.3	4.1	3.5	4.3	-
New hydro	5.3	6.0	6.6	-	7.5	-
Biomass CHP	4.4	4.3	4.3	4.4	4.9	5.6
Solar PV	5.7	6.3	8.5	6.4	6.8	8.8

Source: ECA

6.3 Variation in cap and floor pricing

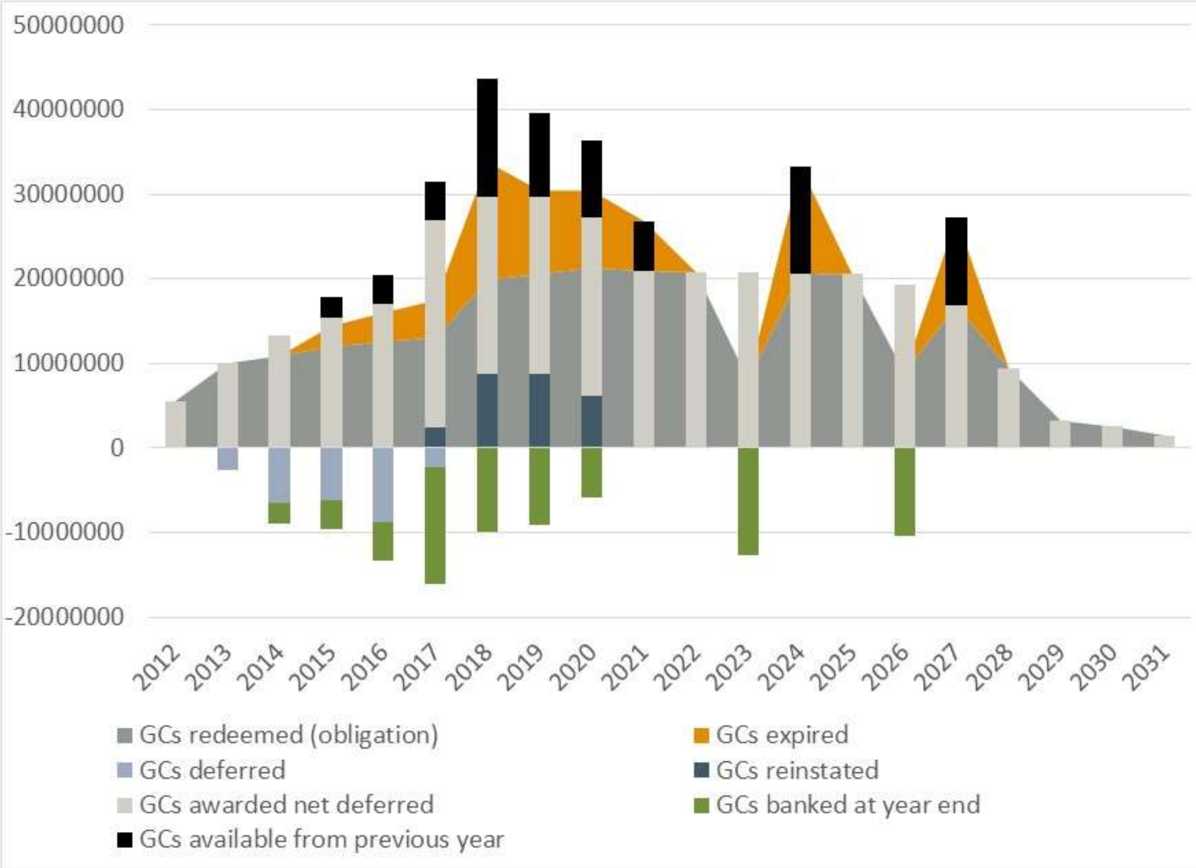
As shown through the previous examples, the nature of certificate mechanisms in the structure of Romania's GC scheme is such that prices tend to either the maximum or minimum regulated values due to the near vertical supply and demand curves. Therefore varying the allowed levels of these prices may have a role to play in rebalancing the GC market. We concentrate on varying the minimum price here due to (a) the projected continued oversupply for GCs under the current methodology for setting the quota obligation and (b) the fact our "targeted obligation" profile is set to purposefully encompass a small oversupply of GCs[11].

6.3.1 Changing the minimum price with the current obligation methodology

Lowering the minimum price, while maintaining the current obligation methodology, to €20/GC and taking a mechanistic approach to the formulae for setting the obligation has the surprising effect of increasing GCs which expire and adding to the burden on consumers while improving returns for RES producers. This is because of the process described in Section 5.3.3 whereby taking the previous years' GC price in setting the quota at a time when supply and demand for GCs are close to being in balance can in itself change the realised market price in the current year from max to min or vice-versa. Figure 26 illustrates this result.

[11] The targeted obligation quota design could also be made so as to aim for small undersupply and rely on the maximum price when judging a fair balance of impact between consumers and producers. In this case the penalty price need be lowered considerably or scrapped as it will in effect act as a tax on consumption when paid by suppliers for the inevitable missed targets.

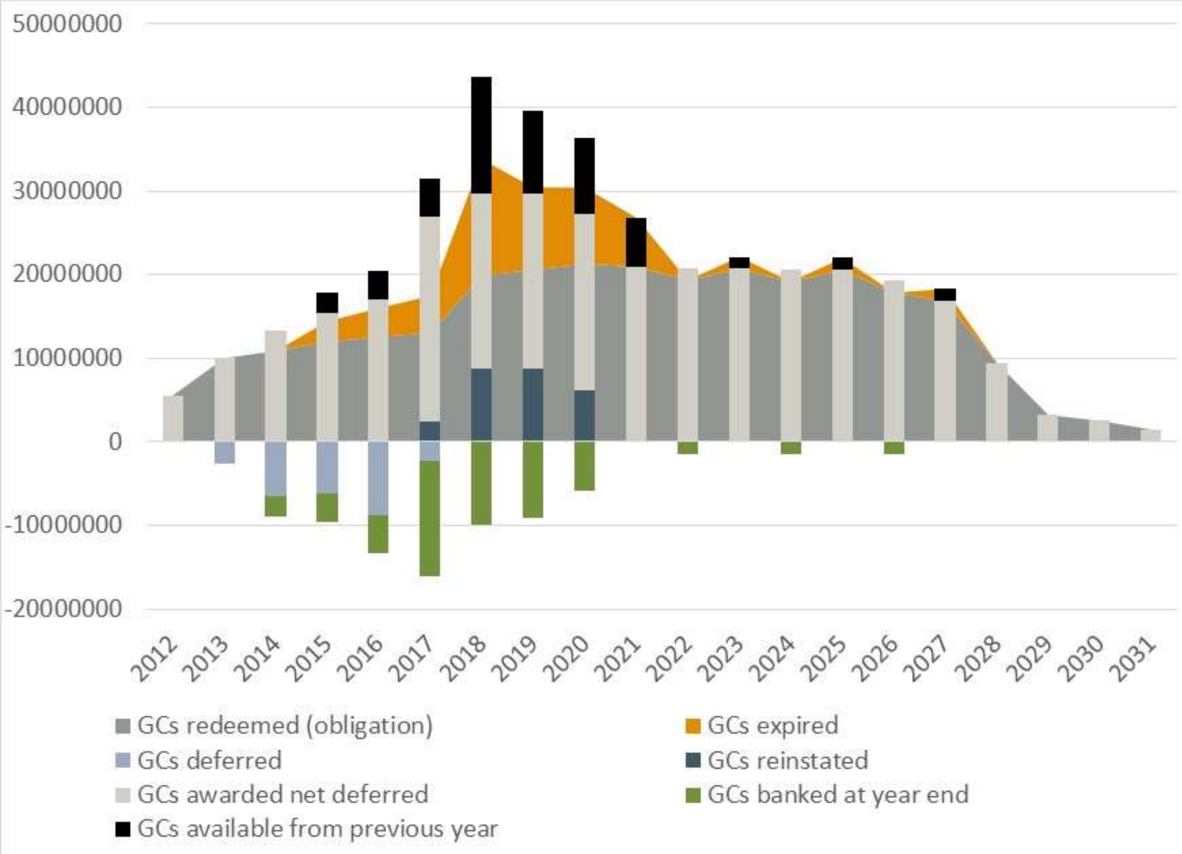
Figure 26 Projected GC market profile with reduced minimum price under current obligation methodology



Source: ECA

However, we note that ANRE has the option to use a different price when setting the obligation if they believe it is likely to change substantially from the previous year. By manually setting the expected price slightly above the actual model result, together with setting a minimum price of €20/GC, a profile such as that shown in Figure 27 (and tabulated in Table 19) can instead be achieved. In this scenario the impact on consumers falls below that for the baseline (central) case for most years, as indicated in Figure 28 and Figure 29. The yearly prices used for this result are provided in Table 20.

Figure 27 Projected GC market profile with reduced minimum price and manually set price forecast under current obligation methodology



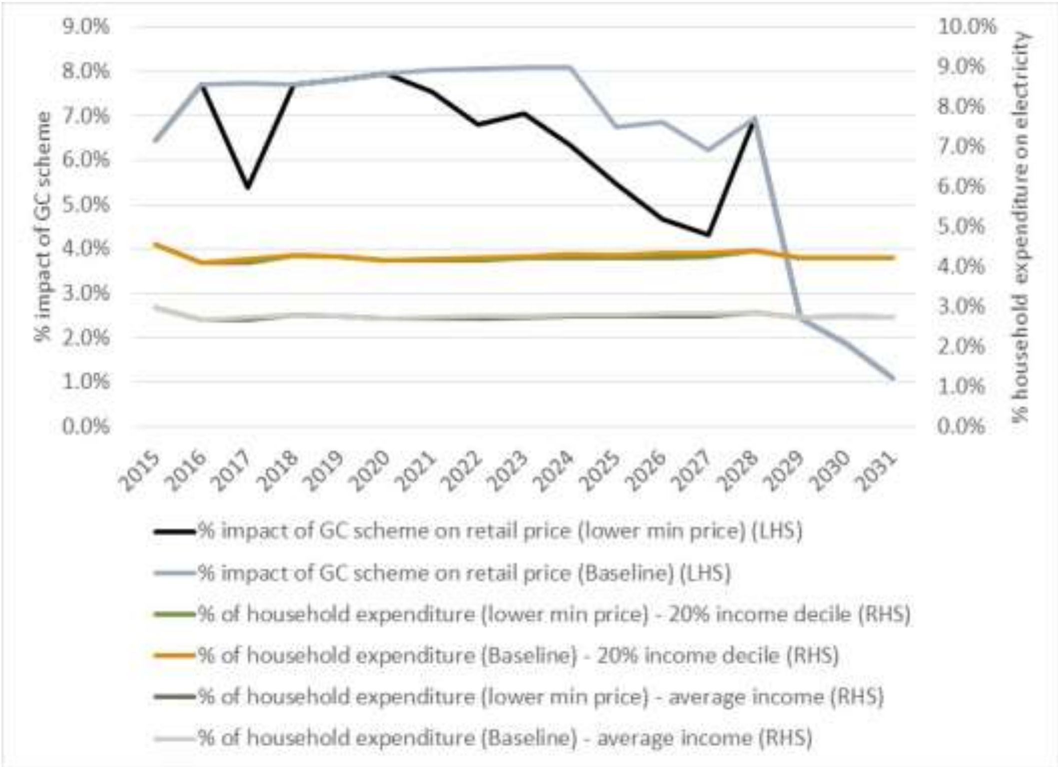
Source: ECA

Table 19 Projected GC market profile with reduced minimum price and manually set price forecast under current obligation methodology

	'16	'17	'18	'19	'20	'21	'22	'23	'24	'25	'26	'27	'28	'29	'30	'31
Red-eemed	12.6	13.1	19.9	20.6	21.3	20.9	19.4	20.7	19.2	20.5	17.9	16.8	9.5	3.2	2.5	1.5
Expired	3.4	4.4	13.9	9.8	9.1	5.9	0.0	1.4	0.0	1.5	0.0	1.5	0.0	0.0	0.0	0.0
Deferred	8.8	2.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Re-instated	0.0	2.5	8.7	8.7	6.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Awarded net deferred	17.0	24.5	21.0	21.0	21.0	20.9	20.8	20.7	20.6	20.5	19.3	16.8	9.5	3.2	2.5	1.5
Banked	4.4	13.9	9.8	9.1	5.9	0.0	1.4	0.0	1.5	0.0	1.5	0.0	0.0	0.0	0.0	0.0
Avail-able from previous year	3.4	4.4	13.9	9.8	9.1	5.9	0.0	1.4	0.0	1.5	0.0	1.5	0.0	0.0	0.0	0.0

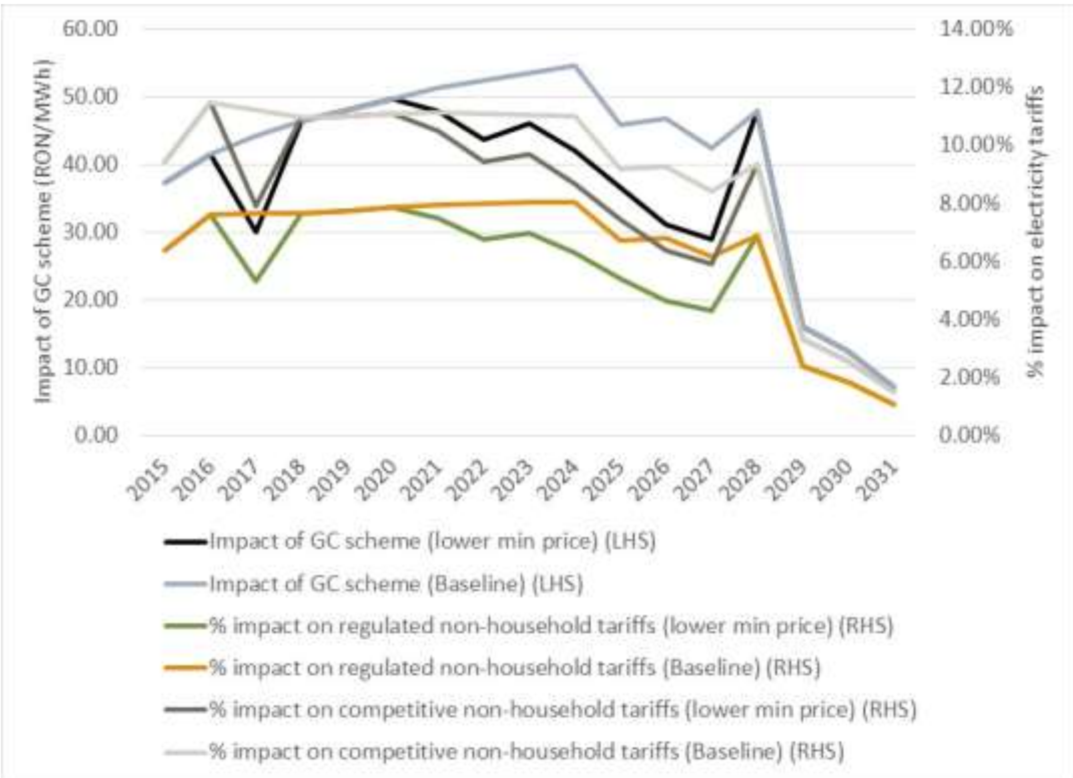
Source: ECA

Figure 28 Impact on households with reduced minimum price and manually set price forecast



Source: ECA

Figure 29 Impact on non-households with reduced minimum price and manually set price forecast



Source: ECA

Table 20 Adjusted minimum price and estimated prices

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Minimum price [€/GC]	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20
Estimated price [€/GC]	20	20	20	20	20	24	20	26	20	30	20	60	60	60	60

Source: ECA

However in this case with the smoothed profile the average IRR results for producers do fall slightly as per Table 21, even if fewer expired GCs means fewer producers receiving no income for their GCs at all. RES producers – particularly wind power plants - also remain cash flow negative until 2018.

Table 21 RES-E generator estimated Modified IRRs (real terms) with manually set pricing

	Average Modified IRR (%) for RES-E capacity by year of accreditation					
	2011	**2012**	**2013**	**2014**	**2015**	**2016**
Central						
Wind	3.3	3.4	3.1	3.0	4.0	-
New hydro	4.2	4.9	5.4	-	7.0	-
Biomass CHP	2.8	2.4	2.0	2.7	3.6	4.7
Solar PV	4.3	4.9	7.0	5.5	6.2	8.5

Source: ECA

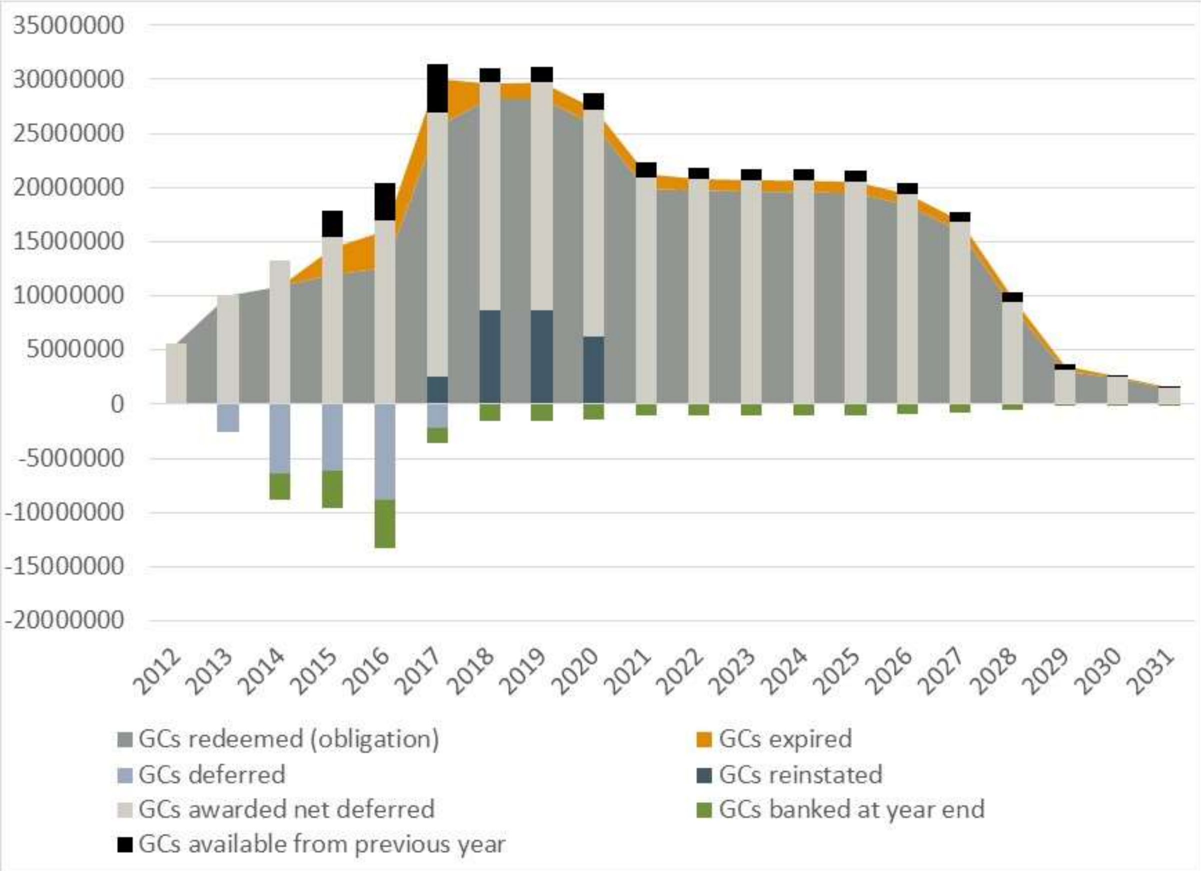
In Section 6.4, we investigate these and some additional pricing options in combination with varying the reinsertion rate.

6.3.2 Changing the minimum price in the "targeted obligation" scenario

By purposefully setting the GC obligation at a level that gives a small surplus in the number of GCs available, the "targeted obligation" methodology will typically drive prices to the minimum and avoid the need to manage the oscillation effect directly though the minimum price and estimated market price.

We have also investigated setting the minimum price to €20/GC (in 2015 EUR) in the targeted obligation scenario. The resulting GC market projected profile is shown in Figure 30 below (and tabulated in Table 22). This outcome is quite similar to that seen in Section 6.1.1, but with greater affordability for consumers, as after an initial price spike the impact on consumers is significantly lower than the baseline from 2021 onwards (Figure 31 and Figure 32). However, the returns for RES-E plant owners are also significantly reduced (Table 23), with a cash flow profile similar to that in Section 6.1.1 but with even more pronounced negative periods. This is a result of the highly uneven availability of GCs over the period. In Section 6.4 below we look at how changes to the minimum price may be used in conjunction with slowing the reinsertion rate of GCs in order to help mitigate for this effect.

Figure 30 Targeted obligation with reduced minimum price



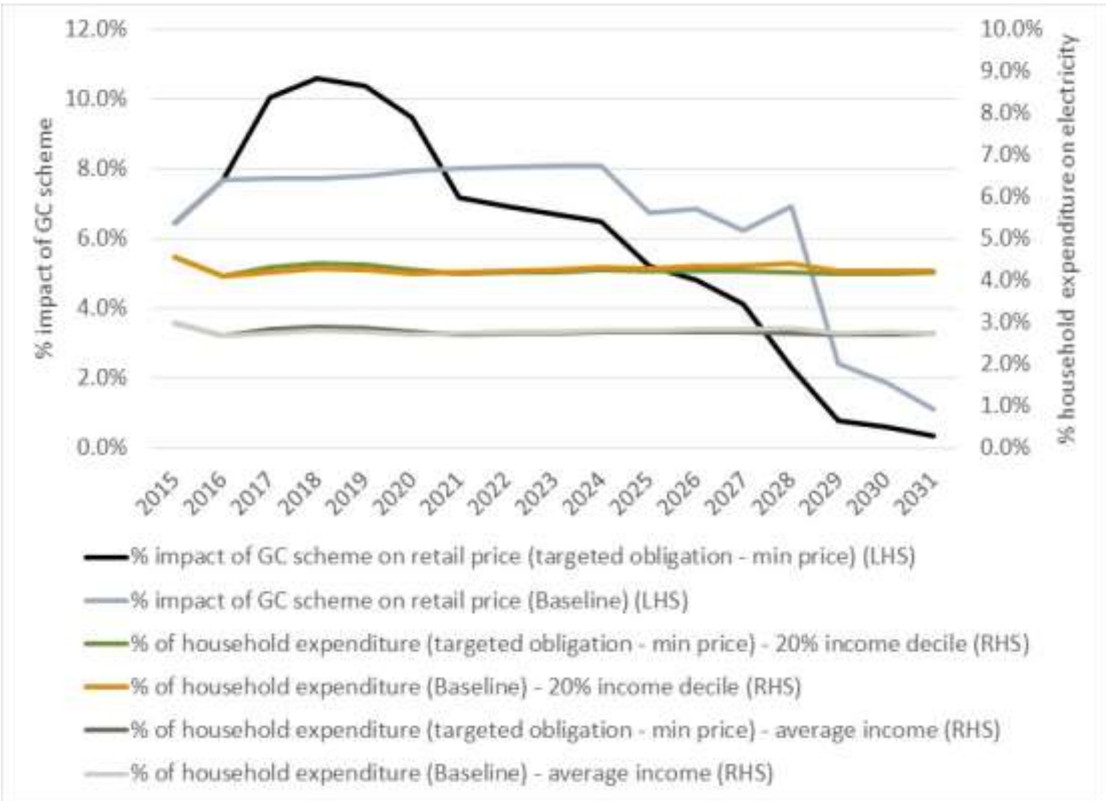
Source: ECA

Table 22 Targeted obligation with reduced minimum price

	'16	'17	'18	'19	'20	'21	'22	'23	'24	'25	'26	'27	'28	'29	'30	'31
Red-eemed	12.6	25.6	28.2	28.2	25.9	19.9	19.8	19.7	19.6	19.5	18.4	16.0	9.0	3.1	2.4	1.4
Expired	3.4	4.4	1.3	1.5	1.5	1.4	1.0	1.0	1.0	1.0	1.0	1.0	0.8	0.5	0.2	0.1
Deferred	8.8	2.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Re-instated	0.0	2.5	8.7	8.7	6.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Awarded net deferred	17.0	24.5	21.0	21.0	21.0	20.9	20.8	20.7	20.6	20.5	19.3	16.8	9.5	3.2	2.5	1.5
Banked	4.4	1.3	1.5	1.5	1.4	1.0	1.0	1.0	1.0	1.0	1.0	0.8	0.5	0.2	0.1	0.1
Avail-able from previous year	3.4	4.4	1.3	1.5	1.5	1.4	1.0	1.0	1.0	1.0	1.0	1.0	0.8	0.5	0.2	0.1

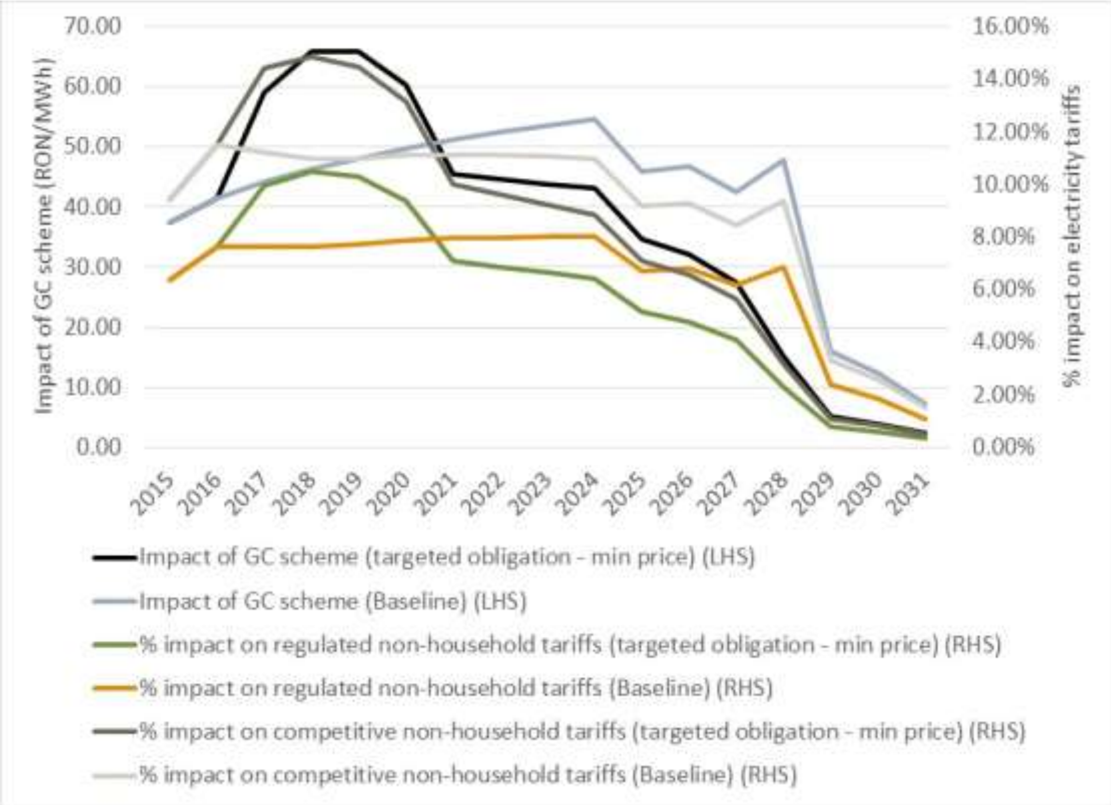
Source: ECA

Figure 31 Targeted obligation with reduced minimum price – impact on households



Source: ECA

Figure 32 Targeted obligation with reduced minimum price – impact on non-households



Source: ECA

Table 23 RES-E generator estimated IRRs (real terms) with targeted obligation and reduced minimum price

	Average IRR (%) for RES-E capacity by year of accreditation					
	2011	2012	2013	2014	2015	2016
Central						
Wind	3.6	3.7	3.4	3.0	3.7	-
New hydro	4.5	5.2	5.6	-	6.6	-
Biomass CHP	3.2	2.9	2.3	2.2	2.4	3.0
Solar PV	4.7	5.3	7.2	5.4	5.7	7.6

Source: ECA

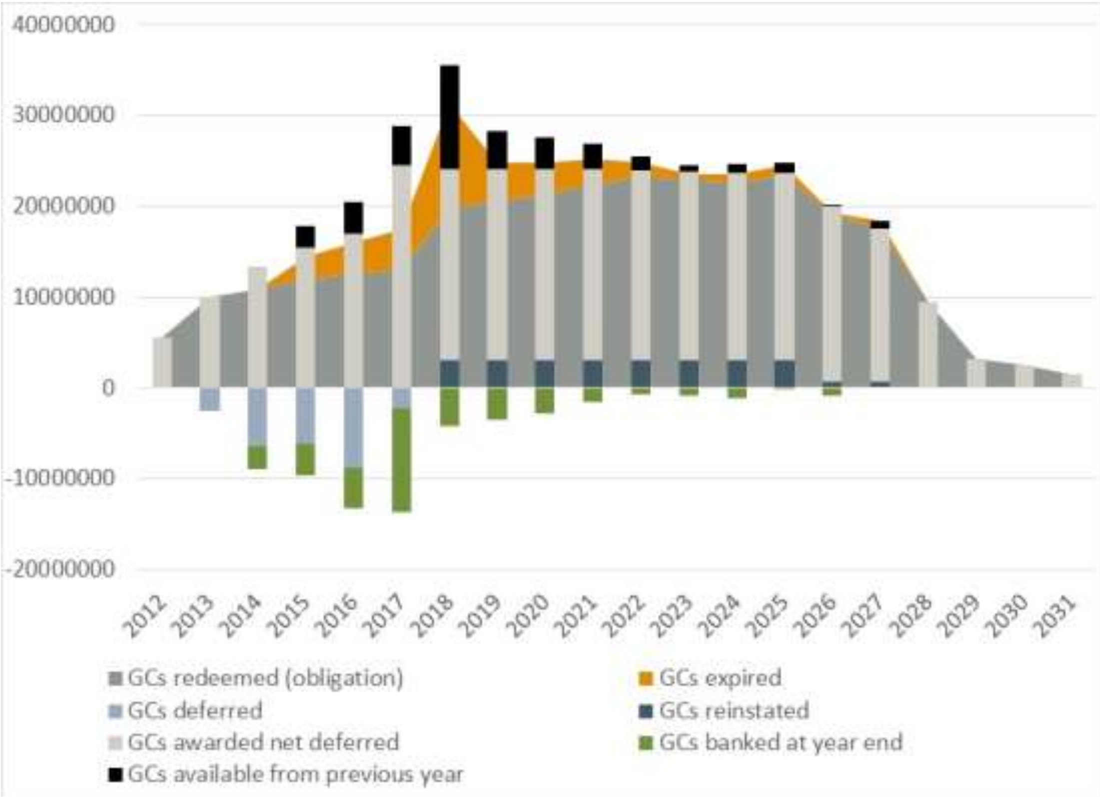
6.4 Variation in floor pricing and reinsertion rate

Here we combine the lower minimum floor price and slower reinsertion rate policy options with each of the current obligation methodology and "targeted obligation" GC quota methodology cases. By combining these policies, we can aggregate the benefits these policies bring by "smoothing" the GC market.

6.4.1 Changing minimum price and slowing reinsertion with current obligation methodology

Manually setting a minimum price of €20/GC and altering the price of certificates to pre-empt forecasted price spikes leads to the profile in Figure 33 (and tabulated in Table 24). We see a much smoother GC market as the obligation more closely follows supply as we manually change the estimated price of GCs, as done in Section 6.2.

Figure 33 Projected GC market profile with reduced minimum price, manually set price forecast and extended reinsertion under current obligation methodology



Source: ECA

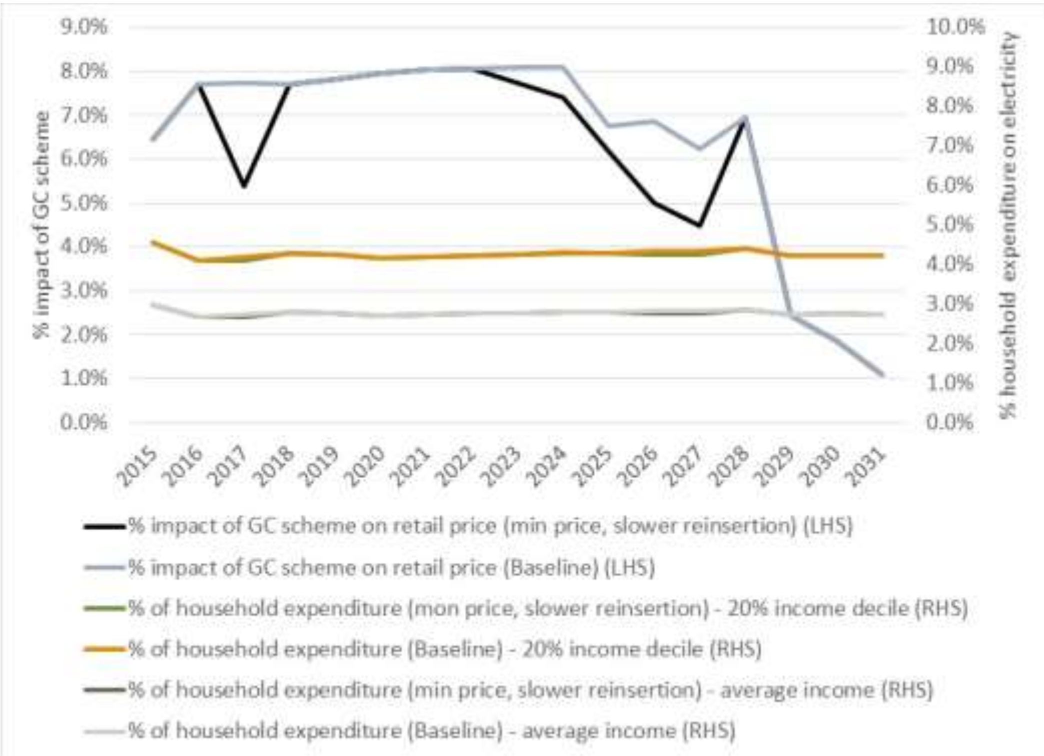
Table 24 Projected GC market profile with reduced minimum price, manually set price forecast and extended reinsertion under current obligation methodology

	'16	'17	'18	'19	'20	'21	'22	'23	'24	'25	'26	'27	'28	'29	'30	'31
Red-eemed	12.6	13.1	19.9	20.6	21.3	22.4	23.2	22.9	22.7	23.5	19.1	17.5	9.5	3.2	2.5	1.5
Expired	3.4	4.4	11.4	4.2	3.5	2.8	1.6	0.7	0.9	1.1	0.2	0.9	0.0	0.0	0.0	0.0
Deferred	8.8	2.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Re-instated	0.0	0.0	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	0.7	0.7	0.0	0.0	0.0	0.0
Awarded net deferred	17.0	24.5	21.0	21.0	21.0	20.9	20.8	20.7	20.6	20.5	19.3	16.8	9.5	3.2	2.5	1.5
Banked	4.4	11.4	4.2	3.5	2.8	1.6	0.7	0.9	1.1	0.2	0.9	0.0	0.0	0.0	0.0	0.0
Avail-able from previous year	3.4	4.4	11.4	4.2	3.5	2.8	1.6	0.7	0.9	1.1	0.2	0.9	0.0	0.0	0.0	0.0

Source: ECA

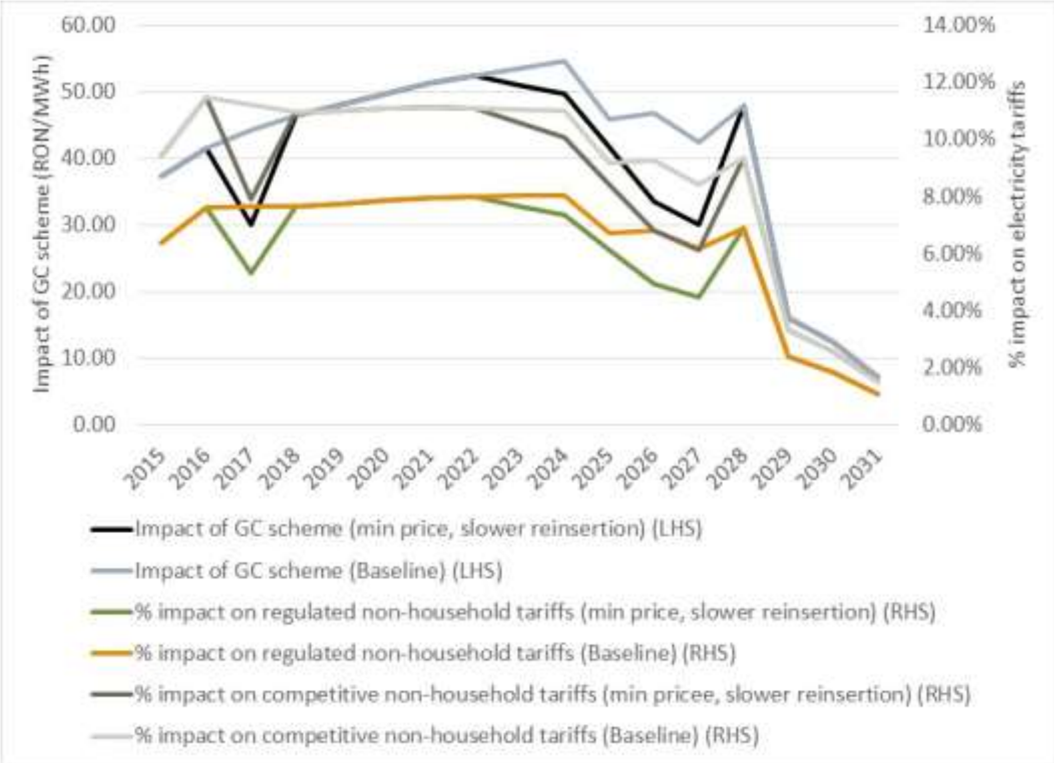
The impact on consumers is also generally lower across the time frame, as seen in Figure 34 and Figure 35.

Figure 34 Impact on households with reduced minimum price, manually set price forecast and extended reinsertion under current obligation methodology



Source: ECA

Figure 35 Impact on non-households with reduced minimum price, manually set price forecast and extended reinsertion under current obligation methodology



Source: ECA

However, this approach does cause lower returns for RES plants (Table 25), which are better able to redeem their GCs over the timeframe and benefit from extended reinsertion, but are still unable to benefit from the price spikes that would have occurred otherwise.

Table 25 RES-E generator estimated Modified IRRs (real terms) with reduced minimum price, manually set price forecast and extended reinsertion under current methodology

	Average Modified IRR (%)for RES-E capacity by year of accreditation					
	2011	**2012**	**2013**	**2014**	**2015**	**2016**
Central						
Wind	3.4	3.5	3.2	3.1	4.1	-
New hydro	4.3	5.0	5.6	-	7.1	-
Biomass CHP	2.9	2.6	2.3	2.9	3.9	4.9
Solar PV	4.5	5.0	7.2	5.7	6.3	8.6

Source: ECA

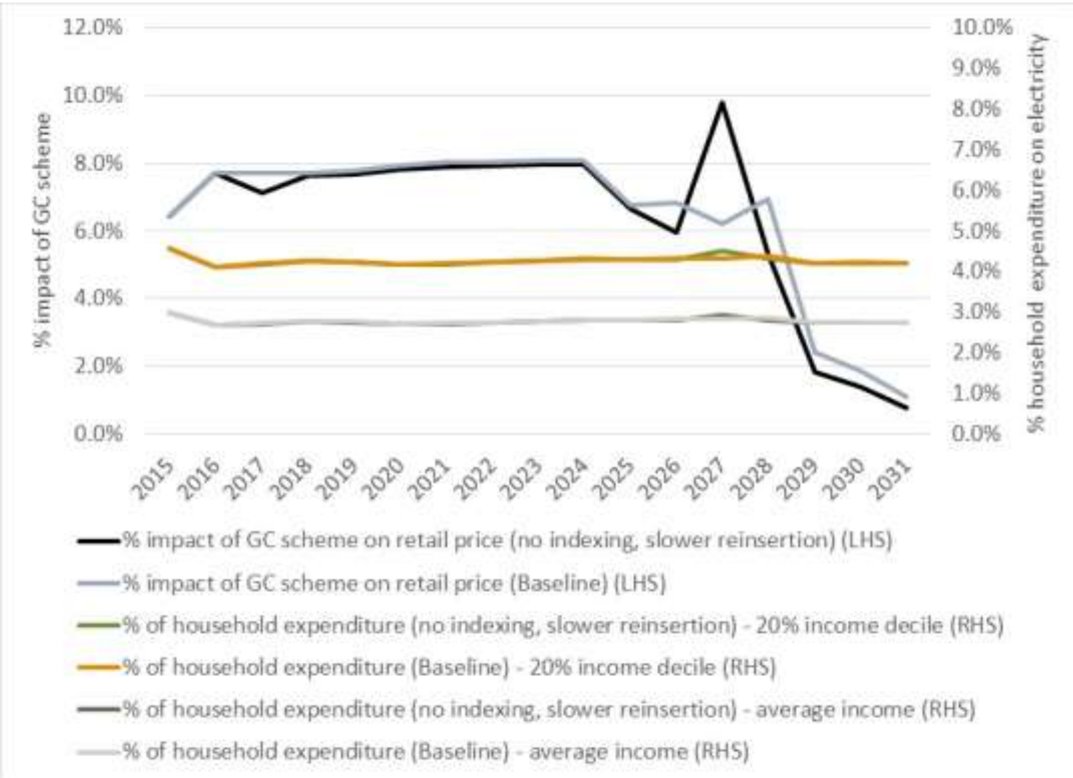
Decoupling from inflation indexation

A less drastic change is to simply uncouple the indexing of the minimum and maximum prices from the inflation indexing. Under this approach, the prices will remain at their initial nominal values of €27/MWh and €55/MWh respectively and then drop in real terms in line with the realised inflation rate each year. The lowering of the maximum price in this way also has the effect of dampening price spikes in later years.

To model this approach we have assumed Euro inflation rates of 0.2% for 2016, 1.1% for 2017 and 1.8% thereafter. The result for consumer impact is similar to the case of slowing reinsertion while maintaining the current obligation methodology described in Section 6.2.1 case with indexation until 2025 (Figure 36 and Figure 37). This is due to the aggregate allowed impact on consumers being the same in both cases so, while a surplus exists, the effect is that a greater proportion of GCs will be sold in the non-indexed case equating to the same total value (averaging 73% between 2017 and 2025 as opposed to 64% in the indexed case). A price spike occurs in 2027 but its height is dampened by the reduced maximum price and indeed, if correctly forecast, the current methodology would allow ANRE to mitigate for it further as in the manually set pricing case reported above.

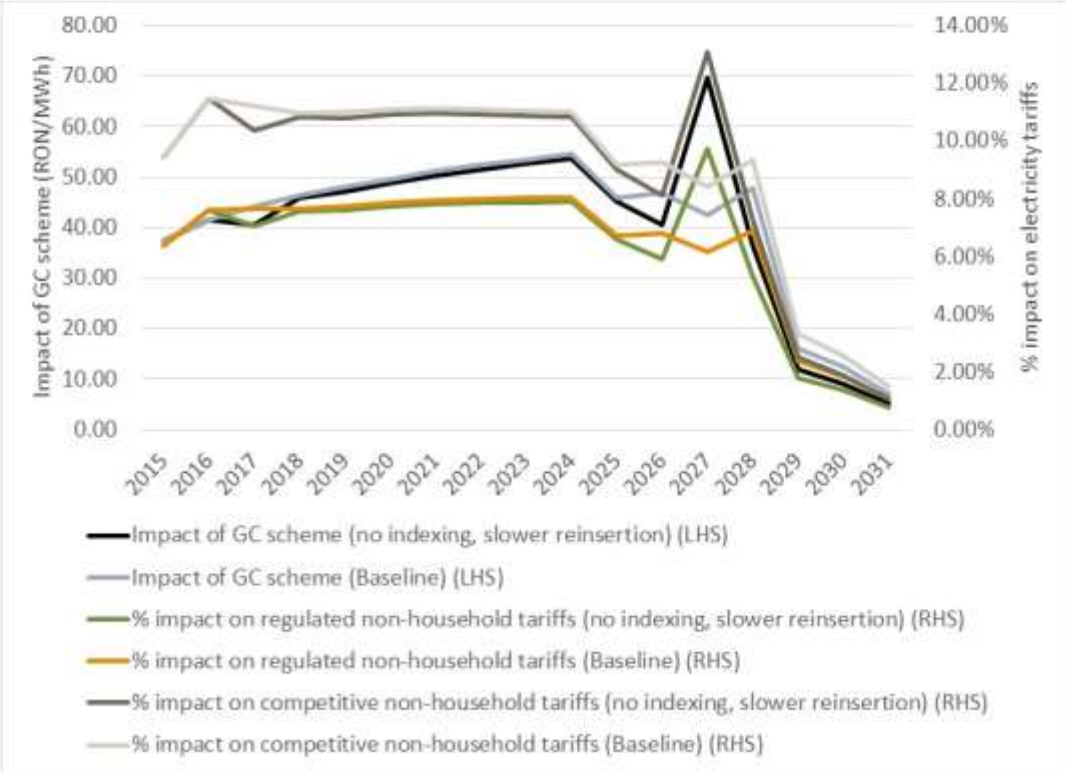
As our revenue calculations assume GCs are successfully sold by each RES-E producer in proportion to the overall market, the average returns to 2025 remain the same as for the baseline case with small differences in the estimated MIRRs (Table 26) only arising due to the end of a surplus from 2026. This result, however, disguises the likely reality that not all RES-E producers are able to sell GCs in a shortage situation at equivalent rates. By raising the quota but reducing the minimum price the impact on consumers can be kept the same as in the baseline case while distributing revenues more evenly across RES-E producers.

Figure 36 Impact on households with no indexation of maximum and minimum prices and extended reinsertion under current obligation methodology



Source: ECA

Figure 37 Impact on non-households with no indexation of maximum and minimum prices and extended reinsertion under current obligation methodology



Source: ECA

Table 26 RES-E generator estimated Modified IRRs (real terms) with no indexation of maximum and minimum prices and extended reinsertion under current methodology

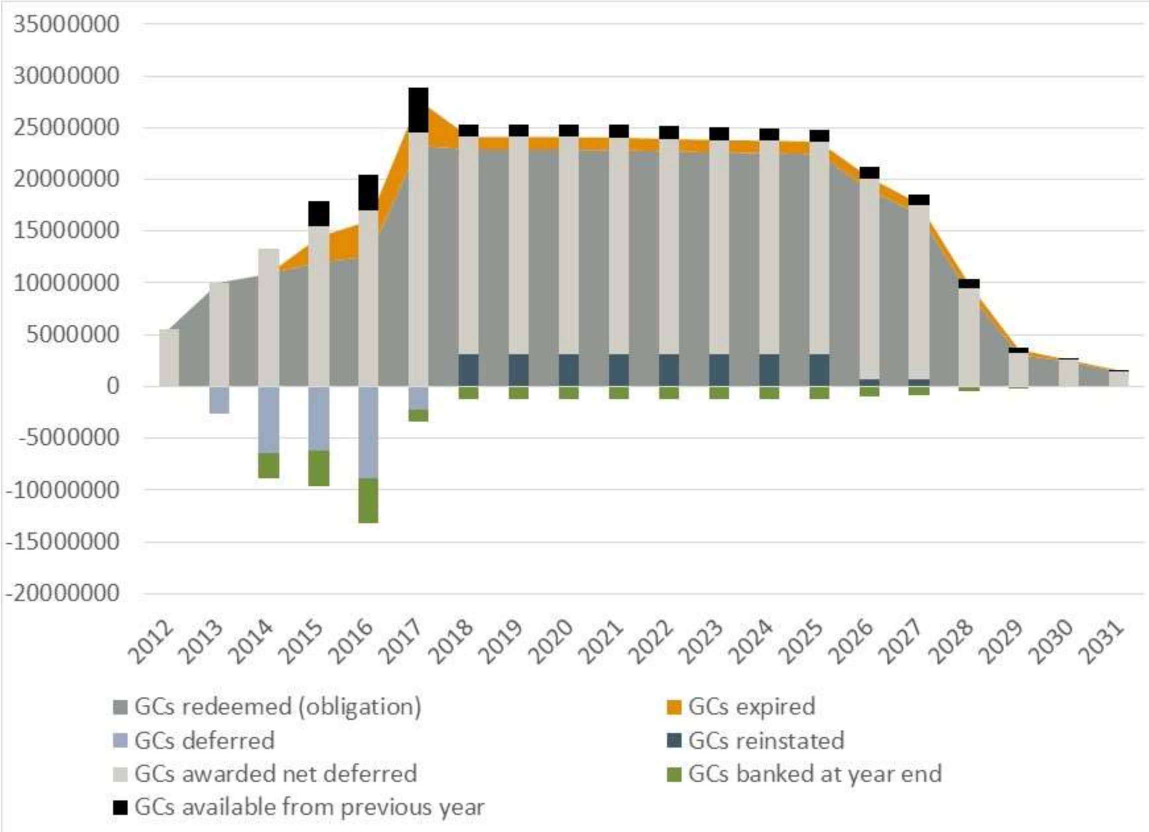
	Average Modified IRR (%) for RES-E capacity by year of accreditation					
	2011	**2012**	**2013**	**2014**	**2015**	**2016**
Central						
Wind	3.5	3.6	3.4	3.2	4.1	-
New hydro	4.4	5.2	5.8	-	7.1	-
Biomass CHP	3.1	2.9	2.8	3.2	3.9	4.8
Solar PV	4.6	5.3	7.5	5.8	6.3	8.4

Source: ECA

6.4.2 Changing minimum price and slowing reinsertion in the "targeted obligation scenario"

We repeat the exercise under the "targeted obligation" scenario, adjusting the minimum price and extending the reinsertion rate up to 2026 for wind and hydro and 2028 for solar. The case with a minimum price of €20/GC is shown in Figure 38 (and tabulated in Table 27). Compared to the result in section 6.3.2, we see a smoother GC market profile, with less of a "bulge" in GCs between 2017 and 2020.

Figure 38 Projected GC market profile with reduced minimum price and extended reinsertion under "targeted obligation"



Source: ECA

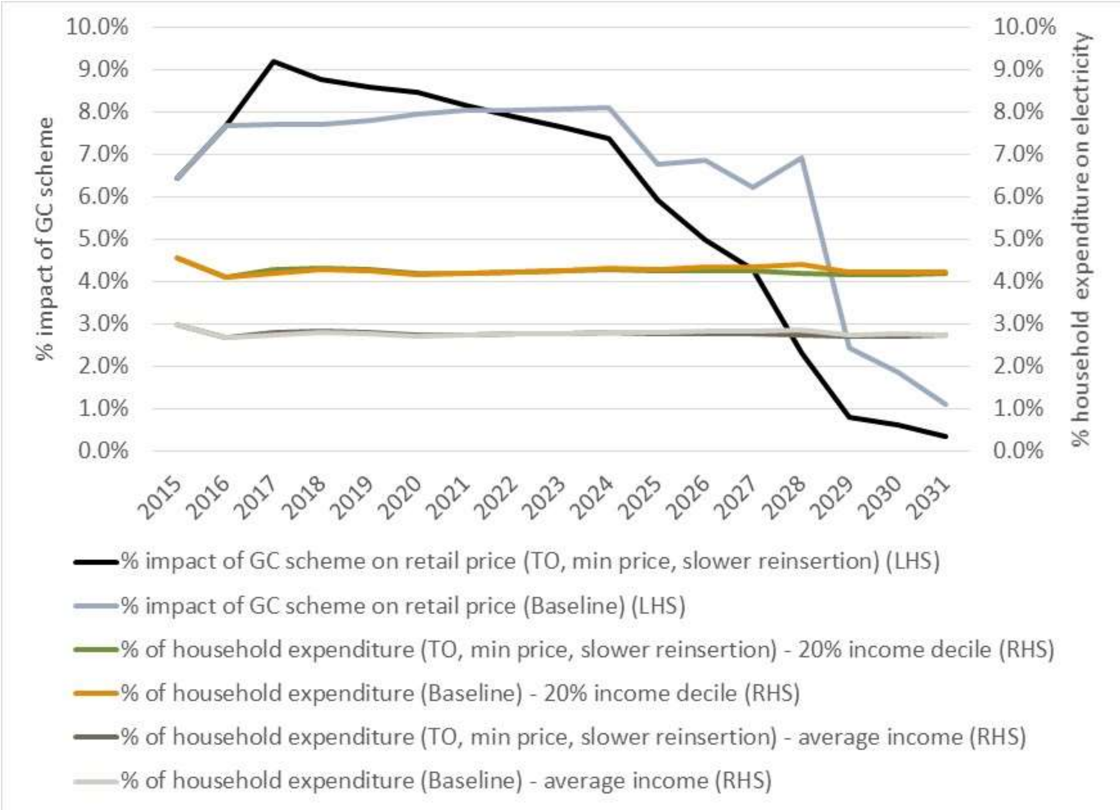
Table 27 Projected GC market profile with manually set minimum price and extended reinsertion under "targeted obligation"

	'16	'17	'18	'19	'20	'21	'22	'23	'24	'25	'26	'27	'28	'29	'30	'31
Red-eemed	12.6	23.3	22.9	22.9	22.9	22.8	22.7	22.6	22.6	22.5	19.0	16.7	9.0	3.1	2.4	1.4
Expired	3.4	4.4	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.0	0.9	0.5	0.2	0.1
Deferred	8.8	2.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Re-instated	0.0	0.0	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	0.7	0.7	0.0	0.0	0.0	0.0
Awarded net deferred	17.0	24.5	21.0	21.0	21.0	20.9	20.8	20.7	20.6	20.5	19.3	16.8	9.5	3.2	2.5	1.5
Banked	4.4	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.0	0.9	0.5	0.2	0.1	0.1
Avail-able from previous year	3.4	4.4	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.0	0.9	0.5	0.2	0.1

Source: ECA

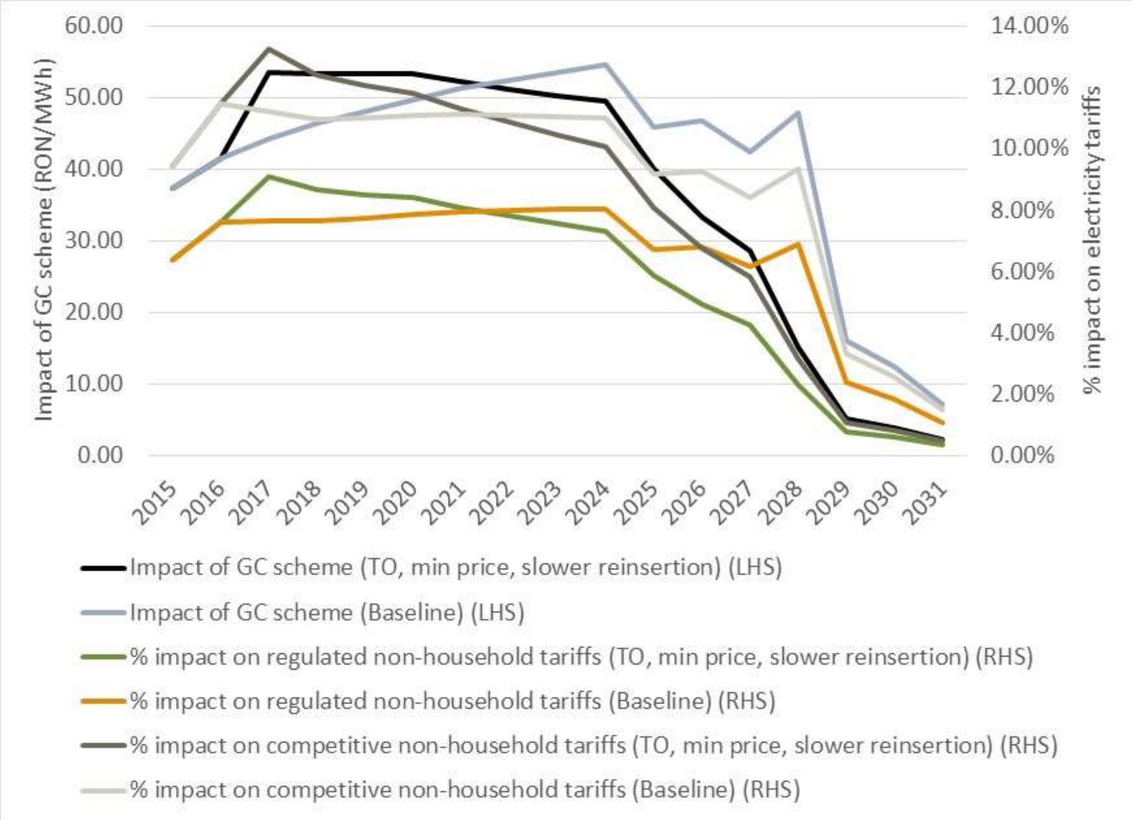
The impact on consumers still rises above the baseline result in the early years before falling lower for the majority of the timeframe from 2021 to 2031 as seen in Figure 39 and Figure 40.

Figure 39 Impact on households with reduced minimum price and extended reinsertion under "targeted obligation (TO)"



Source: ECA

Figure 40 Impact on non-households with reduced minimum price and extended reinsertion under "targeted obligation (TO)"



Source: ECA

However, this approach also causes lower returns overall for RES plants (Table 28), who are better able to redeem their GCs over the timeframe, and benefit from an extended reinsertion rate, but are hit by the lower price and unable to benefit from the price spikes that would have occurred otherwise. We see returns for wind and biomass drop well below 4%.

Table 28 RES-E generator estimated IRRs (real terms) with manually set minimum price and extended reinsertion under "targeted obligation"

	Average IRR (%) for RES-E capacity by year of accreditation					
	2011	2012	2013	2014	2015	2016
Manually set minimum and estimated prices (central)						
Wind	3.5	3.6	3.3	2.9	3.7	-
New hydro	4.5	5.2	5.6	-	6.6	-
Biomass CHP	3.2	2.9	2.3	2.2	2.4	3.0
Solar PV	4.7	5.2	7.2	5.4	5.7	7.6

Source: ECA

To provide an indication of the sensitivity of the above results to the minimum price selected and level of expected surplus built in to the targeted obligation methodology, we have also run the above analysis for both a 5% and 10% targeted surplus for the following cases:

- ❑ A nominal minimum price set at €27/GC (in 2015 EUR) and a maximum price set at a nominal price of €55/GC (in 2015 EUR) with no indexation;
- ❑ A minimum price of €24/GC, indexed to Euro inflation from 2017;
- ❑ A minimum price of €35/GC, indexed to Euro inflation from 2017.

The impact for consumers under the various cases is shown in Table 29, while the impact for RES-E producers is provided in Table 30. The impact for non-household consumers follows the same relative patterns against the consumer impact as for other scenarios presented above.

Table 29 Impact on consumer bills (%) with extended reinsertion and varying minimum price and surplus under "targeted obligation"

	'16	'17	'18	'19	'20	'21	'22	'23	'24	'25	'26	'27	'28	'29	'30	'31
Targeted Obligation with 5% surplus																
No index.	7.7	12.0	11.4	11.0	10.6	10.1	9.6	9.2	8.7	6.9	5.7	4.8	2.6	0.9	0.6	0.4
€24/GC min	7.7	10.8	10.3	10.1	10.0	9.6	9.3	9.0	8.7	7.0	5.9	5.1	2.8	0.9	0.7	0.4
€35/GC min	7.7	15.1	14.4	14.1	13.9	13.5	13.0	12.6	12.2	9.9	8.4	7.3	4.0	1.4	1.0	0.6
Targeted Obligation with 10% surplus																
No index.	7.7	11.4	10.8	10.4	10.1	9.6	9.1	8.7	8.3	6.6	5.4	4.6	2.4	0.8	0.6	0.3
€24/GC min	7.7	10.3	9.9	9.7	9.5	9.2	8.9	8.6	8.3	6.7	5.6	4.8	2.6	0.9	0.7	0.4
€35/GC min	7.7	14.4	13.7	13.5	13.3	12.8	12.4	12.1	11.7	9.5	8.0	6.9	3.8	1.3	1.0	0.6

Source: ECA

Table 30 RES-E generator estimated Modified IRRs (real terms)

	Average Modified IRR (%) for RES-E capacity by year of accreditation					
	2011	**2012**	**2013**	**2014**	**2015**	**2016**
Targeted Obligation with 5% surplus						
No indexation						
Wind	3.8	4.0	3.7	3.3	4.0	-
New hydro	4.9	5.7	6.1	-	7.0	-
Biomass CHP	3.9	3.7	3.4	3.5	3.8	4.4
Solar PV	5.3	5.8	7.9	5.9	6.3	8.2
€24/GC minimum price from 2017						
Wind	3.8	3.9	3.6	3.2	4.0	-
New hydro	4.8	5.6	6.0	-	7.0	-
Biomass CHP	3.7	3.5	3.2	3.3	3.6	4.3
Solar PV	5.2	5.7	7.8	5.8	6.2	8.1
€35/GC minimum price from 2017						
Wind	4.4	4.6	4.5	3.8	4.7	-
New hydro	5.7	6.5	7.1	-	8.0	-
Biomass CHP	5.0	5.0	5.2	5.4	5.9	6.7
Solar PV	6.3	6.9	9.1	6.9	7.3	9.4
Targeted Obligation with 10% surplus						
No indexation						
Wind	3.8	3.9	3.6	3.2	3.9	-
New hydro	4.8	5.5	6.0	-	6.9	-
Biomass CHP	3.7	3.5	3.2	3.1	3.4	4.0
Solar PV	5.2	5.7	7.7	5.7	6.1	8.0
€24/GC minimum price						
Wind	3.7	3.8	3.5	3.1	3.9	-
New hydro	4.7	5.5	5.9	-	6.8	-
Biomass CHP	3.6	3.3	3.0	2.9	3.2	3.9
Solar PV	5.0	5.6	7.6	5.7	6.0	7.9
€35/GC minimum price						
Wind	4.3	4.5	4.4	3.7	4.6	-
New hydro	5.5	6.3	6.9	-	7.8	-
Biomass CHP	4.8	4.8	4.9	5.1	5.5	6.3
Solar PV	6.1	6.7	8.9	6.7	7.1	9.1

Source: ECA

6.5 Variation in banking rules

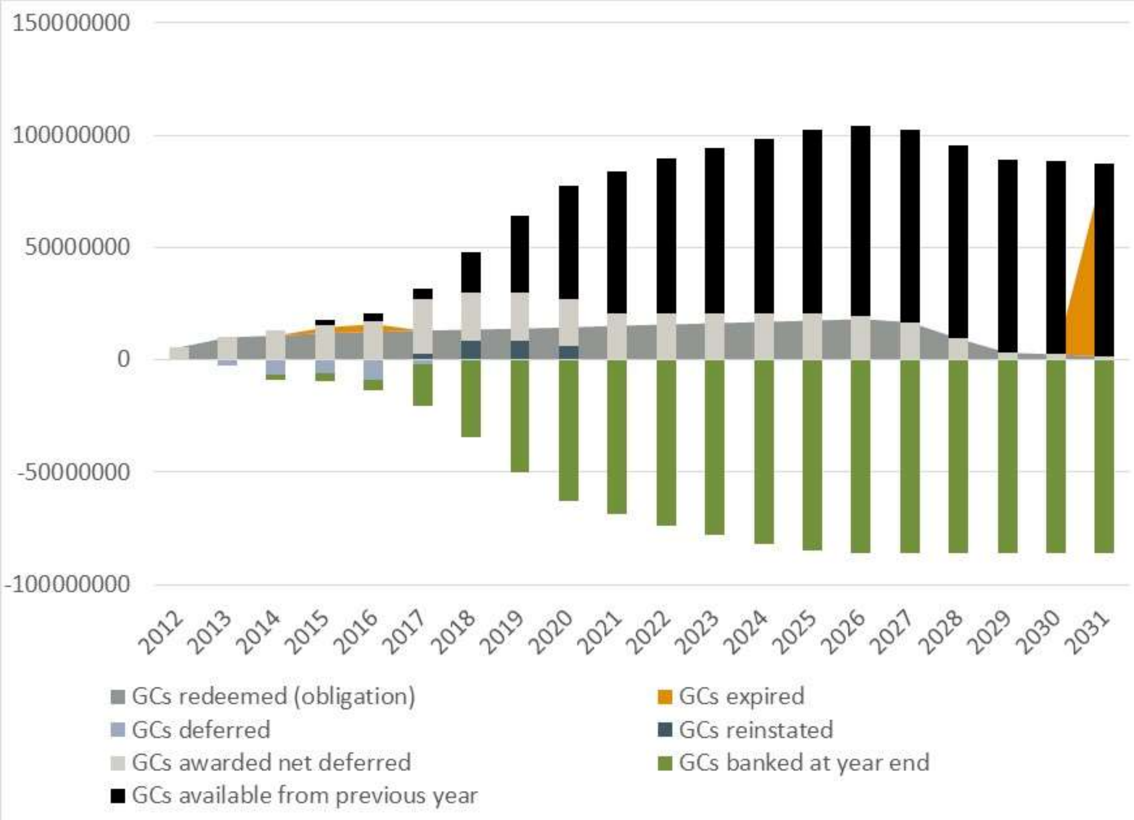
The economics of certificate validity periods and corresponding possibility of banking of certificates were described in Section 2.1.4. The discussion highlighted that banking is only attractive in the case where supply and demand are in reasonable balance. In this section we investigate the effect enabling indefinite banking (i.e. scrapping limit on GC validity before the end of the whole scheme in 2031) in each of the current obligation methodology and "targeted obligation" scenarios. Note that the "static obligation" reported in Section 6.1.2 also enabled indefinite banking as it is a necessary enabling policy for that methodology to operate.

6.5.1 Indefinite banking with the current obligation methodology

In the baseline (central) case illustrated in Section 5.3, oversupply of GCs lasts until 2027 resulting in the price being held at the minimum level until that year. The result being that a significant minority of GCs are left unsold and expire in the following year as their validity ends. Even when the oversupply is projected to end from 2027, the current methodology for setting the obligation caps the number of GCs required to be redeemed by suppliers at the level of the number issued, hence there is no expectation of a future shortage. Nevertheless in these years the cap is exactly equal to the expected number of GCs to be issued and does not allow for any uncertainty margin. Therefore the price is projected to be at a maximum from 2028 once the overhang of GCs from 2026 has expired within 2027.

Allowing for indefinite banking of GCs will enable sufficient banking of GCs in early years to drive the price to the minimum level for the full period to 2031. The resulting projected profile of GCs is presented in Figure 41 (and tabulated in Table 31). As can be seen the large oversupply of GCs accumulates to a point they dwarf the obligation before expiring unsold in the final year of the scheme.

Figure 41 GC market with indefinite validity under current obligation methodology



Source: ECA

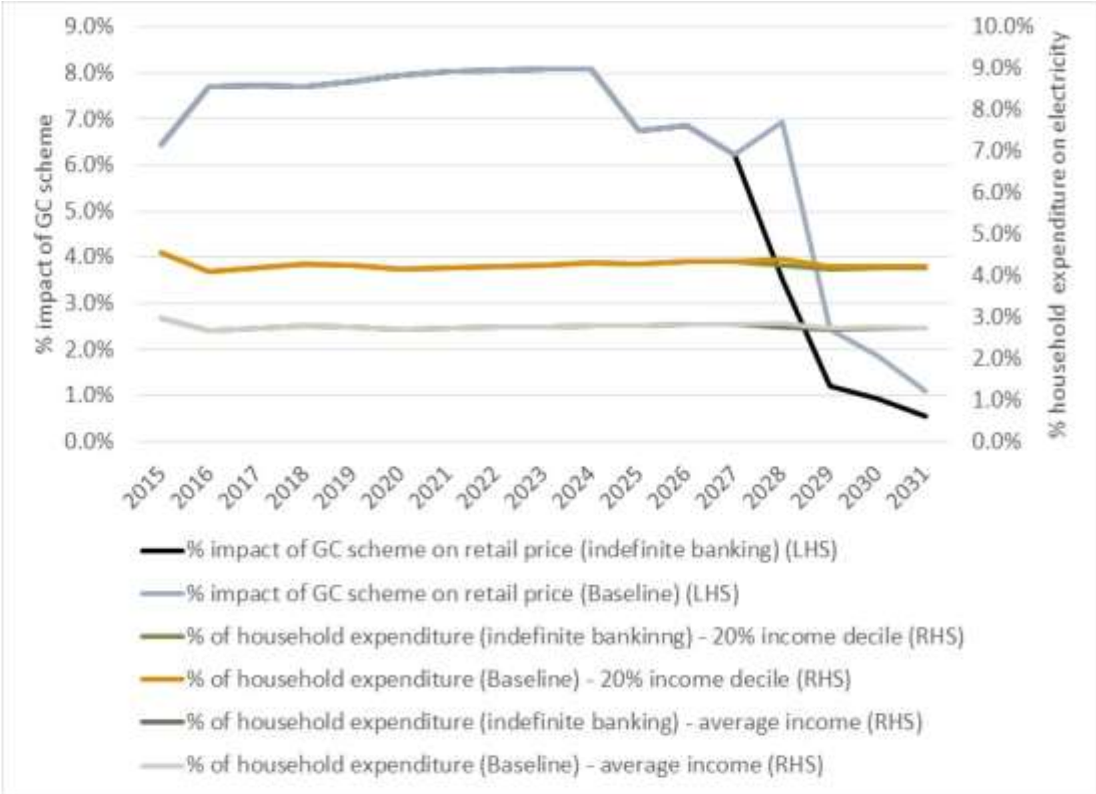
Table 31 GC market with indefinite validity under current obligation methodology

	'16	'17	'18	'19	'20	'21	'22	'23	'24	'25	'26	'27	'28	'29	'30	'31
Red-eemed	12.6	13.1	13.5	14.0	14.5	15.3	15.8	16.4	17.0	17.6	18.2	16.8	9.5	3.2	2.5	1.5
Expired	3.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	85.7
Deferred	8.8	2.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Re-instated	0.0	2.5	8.7	8.7	6.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Awarded net deferred	17.0	24.5	21.0	21.0	21.0	20.9	20.8	20.7	20.6	20.5	19.3	16.8	9.5	3.2	2.5	1.5
Banked	4.4	18.3	34.5	50.2	63.0	68.6	73.6	78.0	81.6	84.6	85.7	85.7	85.7	85.7	85.7	85.7
Avail-able from previous year	3.4	4.4	18.3	34.5	50.2	63.0	68.6	73.6	78.0	81.6	84.6	85.7	85.7	85.7	85.7	85.7

Source: ECA

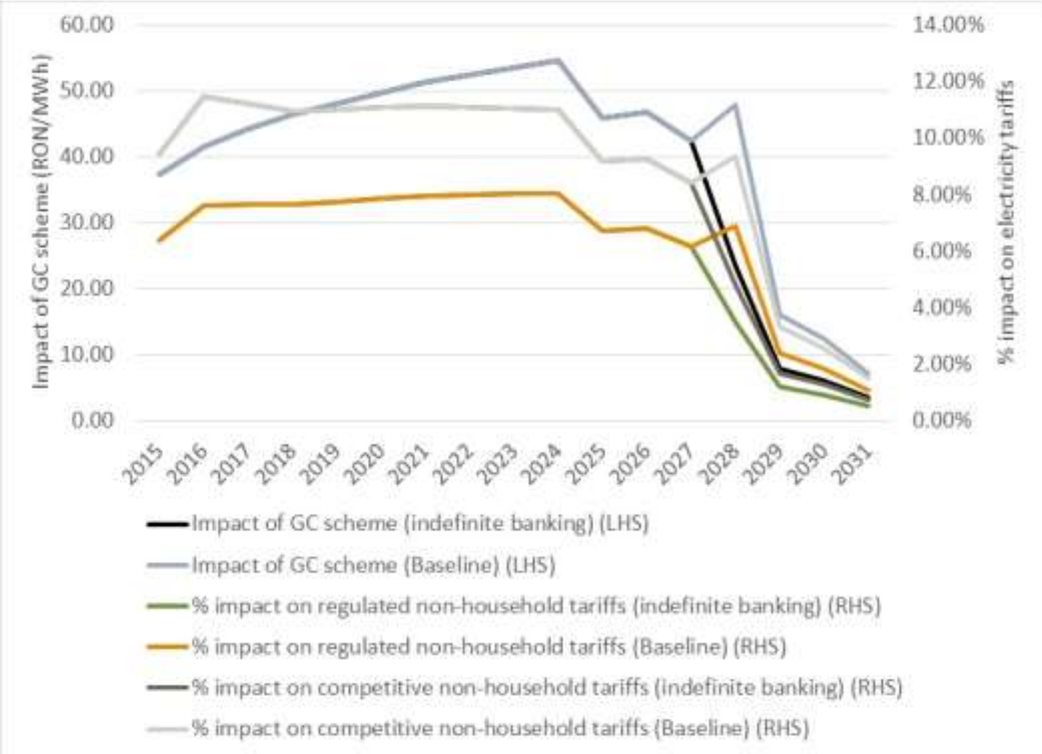
As shown by Figure 42 and Figure 43, the impact on consumers remains the same as in the baseline (central) case until 2025 when the effect of indefinite banking is to retain prices at the minimum regulated level (unlike in the baseline case where the supply shortage results in GC prices rising from this date), generally reducing scheme costs.

Figure 42 Impact on households with indefinite validity under current obligation methodology



Source: ECA

Figure 43 Impact on non-households with indefinite validity under current obligation methodology



Source: ECA

The corresponding impact for RES-E producers is, however, that their revenue will decline in these latter years lowering MIRRs from the baseline (central) case as indicated by Table 32. The impact is greater the later the project was built as the eligibility of earlier projects to the GC scheme begin to cease from 2027.

Table 32 RES-E generator estimated Modified IRRs (real terms) with indefinite validity under current obligation methodology

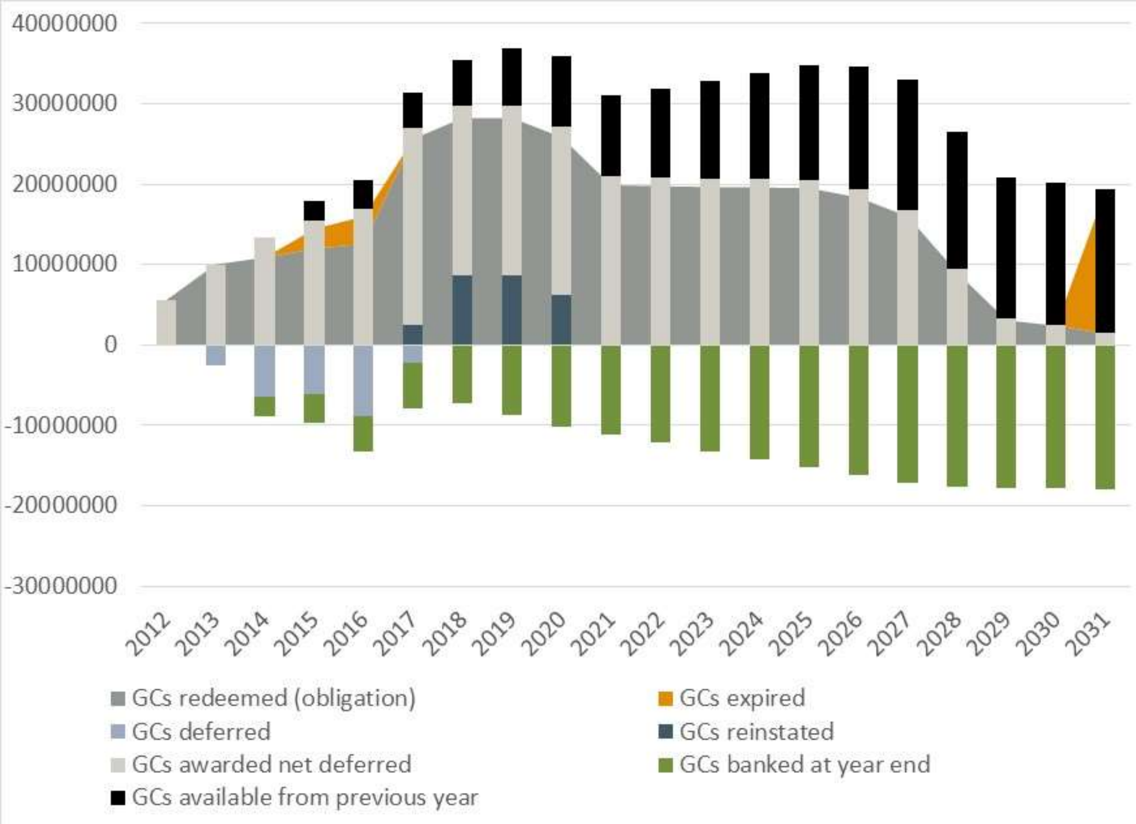
	Average Modified IRR (%) for RES-E capacity by year of accreditation					
	2011	2012	2013	2014	2015	2016
Central						
Wind	3.7	3.8	3.5	3.0	3.6	-
New hydro	4.7	5.4	5.7	-	6.4	-
Biomass CHP	3.4	3.0	2.3	2.0	1.8	2.1
Solar PV	5.0	5.4	7.3	5.3	5.5	7.1

Source: ECA

6.5.2 Indefinite banking in the "targeted obligation" scenario

Enabling indefinite validity for GCs in the "targeted obligation" scenario while making no further alterations, has a similar effect to the current obligation methodology described above in that the annual surplus accumulates (Figure 44, Table 33), although not to the same extent. This is a result of the design of the obligation purposefully to rely on the minimum price. The same "bulge" in consumer price impact occurs as under Section 6.1.1.

Figure 44 GC market with indefinite validity under "targeted obligation" scenario inclusive of surplus



Source: ECA

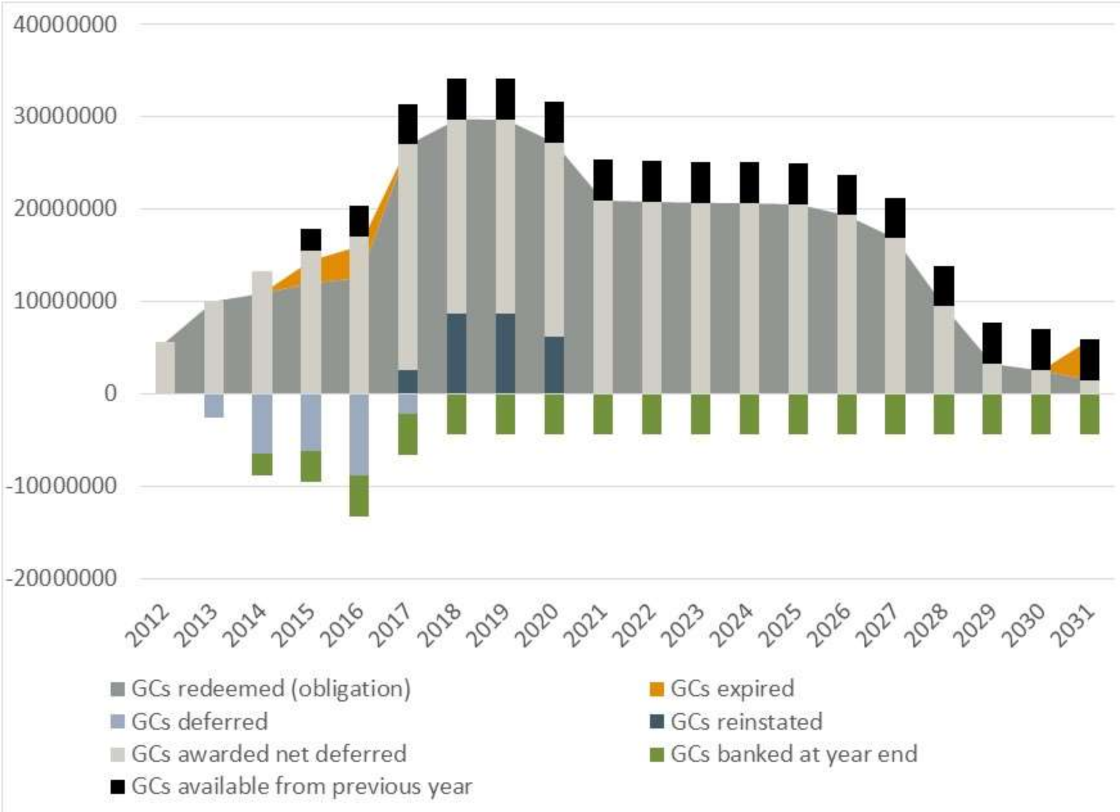
Table 33 GC market with indefinite validity under "targeted obligation" scenario inclusive of surplus

	'16	'17	'18	'19	'20	'21	'22	'23	'24	'25	'26	'27	'28	'29	'30	'31
Red-eemed	12.6	25.6	28.2	28.2	25.9	19.9	19.8	19.7	19.6	19.5	18.4	16.0	9.0	3.1	2.4	1.4
Expired	3.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	17.9
Deferred	8.8	2.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Re-instated	0.0	2.5	8.7	8.7	6.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Awarded net deferred	17.0	24.5	21.0	21.0	21.0	20.9	20.8	20.7	20.6	20.5	19.3	16.8	9.5	3.2	2.5	1.5
Banked	4.4	5.8	7.3	8.7	10.1	11.1	12.2	13.2	14.3	15.3	16.2	17.1	17.6	17.7	17.8	17.9
Avail-able from previous year	3.4	4.4	5.8	7.3	8.7	10.1	11.1	12.2	13.2	14.3	15.3	16.2	17.1	17.6	17.7	17.8

Source: ECA

In the scenario of indefinite GC validity, once a reasonable surplus has been generated it may no longer be necessary to target such a surplus to maintain prices at a minimum as suppliers will have an emergency reserve to draw upon and this will be sufficient to depress prices. Figure 45 shows the same GC market profile with no surplus and ignoring the potential effects of market uncertainty (see Section 6.5.3 below). As the banked GCs from 2016 under this scenario are also provided indefinite validity, the oversupply from that year is sufficient to drive prices down to the minimum level throughout the timeframe of the scheme.

Figure 45 GC market with indefinite validity under "targeted obligation" scenario and no surplus



Source: ECA

The impact on consumers and RES-E producers does not change under the scenario using a small surplus but is slightly higher in both counts (higher cost for consumers, higher return for RES-E producers) under the no surplus scenario as a simple result of the obligation being slightly raised.

6.5.3 The effects of uncertainty in GC supply and demand

The above assessment assumes perfect foresight in that it does not account for the potential for a retailer's consumption to be under- or over-estimated for the year, or uncertainty in the level of RES-E production and thus GC availability.

Under the current methodology, both these factors are revised ex-post the year after to calculate the actual GC obligation faced by retailers following the estimated level calculated ex-ante the year before. The cap on RES-E which may benefit from the promotion scheme that is calculated ex-ante, holds ex-post should the RES-E actually produced prove greater than the cap. Furthermore, retailers are required to purchase GCs on a quarterly basis at a rate which meets at least 90% of the estimated quota, factored by that quarter's actual consumption.

Therefore under the current methodology for setting the obligation, for years where RES-E production proves higher than forecast and no cap is therefore in place (as the national objective was not met for the previous year) the obligation for retailers will also rise. Conversely, if RES-E production falls then the obligation also falls. With perfect information there would therefore be no need for retailers to over-purchase GCs at all (making the demand curve vertical) or unduly chase a scarcity of GCs for years of under-production. Their actual obligation will always be adjusted to realised market conditions ex-post, while quarterly targets based on the estimated obligation likely provide sufficient margin to under-purchase if it were clear that RES-E production had fallen.

However, a retailer will have uncertainty over the actual volume of RES-E which will be produced and their attributable level of final electricity consumption. While we have accounted for this by assuming a steep slope in our demand curve we have not included any revenue from over-purchase in our MIRR calculations. In the case where extended indefinite validity and banking are permitted, a GC reserve held by a given retailer will help them manage the uncertainties discussed above and restrict the need for any over-purchasing. This would in turn have a small downward effect on RES-E producer returns

This assessment also holds for all years in the "targeted obligation" scenario as that scenario would involve scrapping the RES-E cap calculation.

6.6 Variation in heavy industry electricity consumption exemption

Varying the amount of electricity consumption that is exempt from the GC scheme poses another sensitivity analysis. The current exemption has been provided for several energy intensive industries.[12] There is currently 7.5 TWh of exempt electricity for 2016. We shall explore the impact of raising or lowering this exemption by 1,000 GWh, i.e. +/- 13.4% across the entire timeframe of the GC scheme, up until the exemption is set to expire in 2025.

The impact will arise in final tariffs, as changing the amount of exempt electricity consumption will thus change how the cost of the GC scheme is spread across consumers. More exemptions mean non-exempt consumers must bear more of the cost.

The impact of changing the exemption by +/- 1,000 GWh on the cost of GCs per unit if electricity consumed would be fairly minimal. Should 1,000 GWh of additional heavy industry electricity consumption be made exempt, tariffs (for both households and remaining non-exempt non-households) would rise ~3% across the timeframe of the exemption. A 1,000 GWh decline in the exemption would lower household tariffs by ~3%. This result holds whether under both the current obligation methodology and the "targeted obligation" scenario.

6.7 The effect of balancing rules and capping by notification

Intermittent RES plant are further affected by the capping of payment by notified energy as well as the broader balancing market design which penalises all imbalance against the notified level, whether such imbalance is in the same direction as the system as a whole or not. As mentioned previously, wind and solar generators are most affected by this issue albeit approximately half the solar capacity is under the threshold to be designated a

[12] http://www.romania-insider.com/companies-romania-exempted-from-paying-green-certificates/

“dispatching unit” and thus exempt from both the cap on notified volumes and balancing responsibilities.

We have estimated the impact of removing the cap to payments to be based upon notified energy and instead award green certificates upon delivered energy. The effect on wind plant is unsurprisingly more pronounced with a rise in the estimated MIRR of around 0.2% as compared to 0.1% for solar.

While not a policy proposal under this assignment, the model also illustrates the impact should a one-price balancing market be adopted whereby a plant that is out of balance in the opposite direction to the system as whole, benefits by either receiving the deficit price for surplus energy or paying the surplus price for deficit energy. In this case we estimate wind plant on average would see an improvement of around 0.6% in their MIRR while solar would see an improvement in the order of 0.2% (this is an average across all solar capacity - solar plants which are designated as dispatching units would see a proportionately larger gain).

7 Summary and conclusions

7.1 Summary

This has been a detailed study attempting to pull together a multi-dimensional set of variables into a coherent whole. The initial implementation of the GC scheme stimulated investment in renewables beyond expectations leading to a significant overhang of certificates on the market while raising the cost to consumers also beyond expectation.

Policy remedies implemented to date have followed two paths:

- **Containing payments to generators**. These included policies to:
  - Reduce number of certificates awarded per MWh;
  - Deferring award (permission to trade) of some of the certificates;
  - Reducing MWh eligible to receive certificates by awarding not on metered (delivered) energy but on the lower of metered and contracted energy;
  - Shortening the life of certificates to 12 months from award; and
  - Closing scheme to new entrants; and
- **Containing costs to consumers**. These included:
  - Calculating the number of certificates that could be supported by consumers based on fixing the overall cost of the support to only increase in line with consumer demand; and
  - Reducing the levy rate payable by eligible energy intensive users (although this policy only redistributed cost between consumer classes).

ECA was asked to analyse these policy instruments and to model the effect of them as well as to develop scenarios of how they might be applied in amended form. ECA therefore produced a model emulating the policy instruments against a background where the number of certificates to be issued was fixed (no new projects and a defined profile of future expiry of the projects developed – most projects are entitled for certificates to be awarded on MWh generated for a period of 15 years so that the time horizon for the analysis is to 2031). Other variables had to be forecast namely:

- Demand for electricity – as demand grows, consumers can support more certificates at any defined cost per MWh consumed;
- Price of wholesale electricity – generators sell the electricity wholesale and earn green benefits through certificate sales; wholesale prices therefore affect their modified internal rates of return (MIRR);

The outputs of the model were:

- Revenue streams of generators under each scenario and wholesale price forecast, giving:
  - Cash flow; and
  - Modified internal rates of return; and
- Affordability for consumers by consumer class under these scenarios and demand forecasts.

The results show the impact of wholesale price forecasts on generator returns but, as these price effects are exogenous to the policy options, we have based the scenario analyses on the central forecast.

7.2 Scenarios of policy combinations

The following are the key conclusions from the analyses by each scenario or combination of scenarios:

- **Varying the GC quota**:
  - A targeted obligation smooths the GC market, but causes a spike in consumer impact through payment for the increased redemption of previously deferred GCs as they are reinserted to the market.
  - A static obligation with indefinite banking causes heavy banking and an even pace of redemption, which also extends the impact on consumers beyond the current projected end of the scheme.
- **Varying the reinsertion rate**:
  - This steadies the cash flows for RES plants, particularly under the targeted obligation quota methodology, and helps smooth the GC profile and thus impact on consumers. It does also slightly reduce the MIRR of producers who face a delay in earning revenue from GCs.
- **Varying cap and floor pricing**:
  - Lowering the minimum price and varying the estimated GC price in response to expected price spikes helps smooth the GC market profile, and can lower the consumer impact, but this is at the expense of RES plants whose returns are suppressed due to being unable to benefit from the market's price spikes in reaction to not meeting obligations.
  - In the years that remain in a surplus situation, a lowering of the minimum price does not decrease average RES plant returns as the aggregate allowed impact remains the same and thus more GCs can be sold to compensate. This helps mitigate for the potential uneven impact on RES producers from

a low ratio of RES production being permitted to benefit from the promotion scheme under the current methodology.

- **Varying floor pricing *and* reinsertion rate**:

  - This combines the smoothing benefits of lowering the floor price and varying the reinsertion rate, which also balances the benefits to consumers of lowering the floor price (at the cost of RES plant returns once the surplus situation ends) and the benefits to RES plants of varying the reinsertion rate (at the cost of consumers in later years).

    This is very much a compromise policy, sharing the cost of the policy between generators, through the lowered price of certificates sold, and consumers who must pay higher prices for longer.

- **Variation in banking rules**:

  - Allowing indefinite banking benefits consumers who are not hit by price spikes, but ultimately hurts RES plants that heavily bank GCs until a massive expiry at the end of the scheme as the supply of GCs is too large for the obligation.

  - However, implementing a "targeted obligation" (which could be smoothed across the time period as in the case of the "static obligation" scenario) would limit the number of GCs that expire at the end of the scheme and smooth the higher impact on consumers.

Further combinations of policies are possible.

7.3 Conclusions

The GC scheme began with a probably over-generous payout to generators, based on expectations of high IRRs, likely compounded by higher wholesale market price expectations. This led to high generator expectations and rapid investment. This inevitably had a cost to be borne by consumers.

Subsequent policy adjustments to reduce the impact on consumers had the effect of negatively impacting generator cash flows, with an additional adverse effect of many certificates being unsaleable, because demand had reduced faster than supply.

In terms of policy measures, this means playing off reasonable expectations of generators against reasonable cost expectations of consumers. The negative cash flows faced by generators generally in recent years (which is unevenly split with some generators facing a disportionate share of unsold GCs and so a much worse income than others) will almost certainly have to be alleviated to the extent that policy changes against their reasonable expectations were instituted, but this can only be done at the expense of consumers (or taxpayers).

The most likely policy combinations will see improved cash flow for generators, but at a reduced return as compared to initial expectations; for consumers it would be through delaying payments into later years. To achieve positive but steady cash flows requires a combination of increasing the quota and either forced banking of certificates (through deferred trading of them) or voluntary banking by extending the tradable life of certificates.The "targeted obligation" methodology in combination with extended reinsertion of deferred GCs indicates positive cash flows are just about achieved from 2017 or 2018 for all technology and year-of-accreditation groups with the exception of wind plant accredited in 2014 and 2015 (comprising under 12% of wind capacity). Even this case, however, requires a substantial increase in the impact of the GC scheme as a proportion of consumer bills, peaking at over 11% in 2017, while real MIRRs for many technology-year groups remain under 4.5%.

Should such an impact on consumers be deemed unacceptable then a similar approach could be adopted but a reduced minimum price price of certificates added to the mix. This would, however, further reduce returns and prolong the risk of negative cash flows (the impact is least onerous under the "no indexation" approach to reducing the minimum price as this hits hardest in later years after debt service obligations have ended). The resulting financing gap may then require financial measures external to the GC scheme design to be considered (eg securitisation or partial payment through general taxation).

The key results from four scenarios that refelect the above discussed potential policy combinations are provided below.

Table 34 Impact on consumer bills (%) of selected policy combination scenarios

	'16	'17	'18	'19	'20	'21	'22	'23	'24	'25	'26	'27	'28	'29	'30	'31
Targeted Obligation with 5% surplus and extended reinsertion (no change to price levels)																
Impact %.	7.7	13.0	12.4	12.1	12.0	11.6	11.2	10.8	10.5	8.5	7.1	6.2	3.4	1.1	0.9	0.5
Current obligation methodology with extended reinsertion and no indexation of minimum and maximum prices																
Impact %.	7.7	7.1	7.6	7.7	7.8	7.9	7.9	8.0	8.0	6.6	6.0	9.8	5.4	1.8	1.4	0.8
Targeted Obligation with 10% surplus, extended reinsertion and no indexation																
Impact %.	7.7	11.4	10.8	10.4	10.1	9.6	9.1	8.7	8.3	6.6	5.4	4.6	2.4	0.8	0.6	0.3
Static obligation with indefinite validity																
Impact %.	7.7	10.4	10.1	9.9	9.8	9.4	9.2	8.9	8.6	7.0	6.8	6.7	6.6	6.4	6.3	6.2

Source: ECA

Table 35 RES-E generator estimated modified IRRs (real terms) for selected policy combination scenarios

	Average Modified IRR (%) for RES-E capacity by year of accreditation					
	2011	**2012**	**2013**	**2014**	**2015**	**2016**
Targeted Obligation with 5% surplus and extended reinsertion (no change to price levels)						
Wind	4.1	4.3	4.1	3.5	4.3	-
New hydro	5.3	6.0	6.6	-	7.5	-
Biomass CHP	4.4	4.3	4.3	4.4	4.9	5.6
Solar PV	5.7	6.3	8.5	6.4	6.8	8.8
Current obligation methodology with extended reinsertion and no indexation of minimum and maximum prices						
Wind	3.5	3.6	3.4	3.2	4.1	-
New hydro	4.4	5.2	5.8	-	7.1	-
Biomass CHP	3.1	2.9	2.8	3.2	3.9	4.8
Solar PV	4.6	5.3	7.5	5.8	6.3	8.4
Targeted Obligation with 10% surplus, extended reinsertion and no indexation						
Wind	3.8	3.9	3.6	3.2	3.9	-
New hydro	4.8	5.5	6.0	-	6.9	-
Biomass CHP	3.7	3.5	3.2	3.1	3.4	4.0
Solar PV	5.2	5.7	7.7	5.7	6.1	8.0
Static obligation with indefinite validity						
Wind	4.1	4.3	4.1	3.5	4.3	-
New hydro	5.2	6.0	6.5	-	7.5	-
Biomass CHP	4.2	4.1	4.1	4.4	4.9	5.6
Solar PV	5.7	6.2	8.4	6.3	6.7	8.7

Source: ECA

ANNEXES

A1 Input data used in analysis

Table 36 General economic and demographic data

GDP central case (billions)[13]	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
	662	666	690	710	740	767	792	818	844	872	890	908	927
	2025	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**
	947	962	977	992	1,008	1,024	1,040	1,056	1,073	1,090	1,107	1,125	1,142
GDP low case (billions)[13]	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
	662	666	690	710	733	752	769	786	804	822	831	840	849
	2025	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**
	859	863	868	873	879	884	889	894	899	904	909	915	920
GDP high case (billions)[13]	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
	662	666	690	710	747	782	815	850	886	923	952	981	1,011
	2025	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**
	1,043	1,070	1,097	1,125	1,154	1,184	1,215	1,246	1,278	1,311	1,345	1,380	1,415
Population (millions)[14]	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
	-	-	-	19.91	19.87	19.82	19.78	19.73	19.69	19.62	19.55	19.48	19.41
	2025	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**
	19.35	19.28	19.21	19.14	19.07	19.00	18.95	18.90	18.84	18.79	18.73	18.68	18.62
Eurozone inflation rate	**Constant:** 1.8%												
U.S. inflation rate	**Constant:** 2.0%												
Euro-dollar exchange rate[15]	**Constant:** 0.901												
Lieu-Euro exchange rate[16]	**Constant:** 4.5												

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[13] Eurostat used for 2011-2015, IMF World Economic Outlook for 2016-2021. For 2022 and beyond, we took the energy consumption and energy intensity figures given in the EC Reference Scenario for the years 2025 and 2030 to derive a GDP figure and used those figures to extrapolate from the IMF 2021 figure.

[14] Eurostat projections for 2015, 2020, and 2030, assuming a linear trend between these data points.

[15] Average rate for 2015 (source: OANDA) used and assumed to remain constant over time period.

[16] Average rate for 2015 (source: OANDA) used and assumed to remain constant over time period. Note Romania is a member of the European Exchange Rate Mechanism (ERM) II which seeks to stabilise exchange rates with the EUR. The rate has remained in a relatively narrow band between 4.4 and 4.6 since mid-2012.

Table 37 Fuel and power price data

Gas price forecast – European import price (2015€/MWh)[17]	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
	14.4	*14.3*	*14.9*	*15.8*	*16.3*	*17.1*	*17.8*	*18.5*	*19.5*	*20.4*	*20.4*
	2027	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**
	20.4	*20.4*	*20.4*	*20.4*	*20.4*	*20.4*	*20.4*	*20.4*	*20.4*	*20.4*	*20.4*
Crude oil projection (US$/bbl)[18]	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
	43.0	*53.2*	*59.9*	*62.7*	*65.6*	*68.6*	*71.9*	*75.3*	*78.8*	*82.6*	*86.0*
	2027	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**
	89.4	*92.8*	*96.2*	*99.6*	*103.0*	*106.4*	*109.8*	*113.2*	*116.6*	*120.0*	*123.4*
European coal import price (2015US$/t)[19]	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
	47.5	59.6	71.7	83.8	95.9	96.7	97.5	98.3	99.1	100.0	100.8
	2027	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**
	101.6	102.4	103.2	104.0	104.8	105.6	106.4	107.2	108.1	108.9	110.0

[17] Monthly futures contracts from ICE for TTF Netherlands Virtual Trading Point used for 2010 to 2016. World Bank Commodities Market Outlook July 2016 used for 2015 to 2025. Price held at 2025 for 2026 onwards, reflecting gas and oil prices de-linking.

[18] World Bank Commodities Market Outlook July 2016. Data series extended past 2025 by extrapolating the 2020-25 trend.

[19] 2013 – 2016 takes monthly futures contracts for the Amsterdam, Rotterdam, and Antwerp region. Years afterward use the World Bank Commodities Market Outlook July 2016 prices for Australia Newcastle, plus an assumed shipping margin of $8/t.

Table 38 Energy demand data

Final electricity consumption (TWh)[20] - Central case													
Residential	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
	12.0	11.9	11.9	*12.0*	*12.1*	*12.1*	*12.1*	*12.1*	*12.1*	*12.3*	*12.5*	*12.6*	*12.7*
	2025	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**
	12.9	*13.1*	*13.4*	*13.6*	*13.8*	*14.1*	*14.3*	*14.5*	*14.8*	*15.0*	*15.2*	*15.4*	*15.6*
Transport	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
	1.2	1.1	1.1	*1.1*	*1.1*	*1.1*	*1.1*	*1.1*	*1.1*	*1.1*	*1.1*	*1.1*	*1.1*
	2025	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**
	1.2	*1.2*	*1.2*	*1.2*	*1.2*	*1.3*	*1.3*	*1.3*	*1.3*	*1.3*	*1.4*	*1.4*	*1.4*
Tertiary	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
	8.7	8.8	9.1	*9.2*	*9.2*	*9.2*	*9.2*	*9.3*	*9.3*	*9.4*	*9.5*	*9.6*	*9.7*
	2025	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**
	9.8	*10.0*	*10.2*	*10.4*	*10.6*	*10.7*	*10.9*	*11.1*	*11.3*	*11.4*	*11.6*	*11.7*	*11.9*
Energy-intensive industry	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
	15.9	14.3	15.2	*15.3*	*15.4*	*15.4*	*15.4*	*15.4*	*15.4*	*15.7*	*15.9*	*16.0*	*16.2*
	2025	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**
	16.4	*16.7*	*17.0*	*17.3*	*17.6*	*17.9*	*18.2*	*18.5*	*18.8*	*19.1*	*19.4*	*19.6*	*19.8*
Other industrial sectors	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
	8.8	9.1	9.5	*9.6*	*9.7*	*9.7*	*9.7*	*9.7*	*9.7*	*9.9*	*10.0*	*10.1*	*10.2*
	2025	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**
	10.3	*10.5*	*10.7*	*10.9*	*11.1*	*11.3*	*11.5*	*11.6*	*11.8*	*12.0*	*12.2*	*12.3*	*12.5*

[20] Energy consumption data taken from Romania's Energy Balances of 2011-2014 as reported by Eurostat. These figures are used to derive each sector's percentage share of final electricity consumption (including GC-exempt energy-intensive industry). The percentages for 2014 are held constant for each year afterward. Gross final electricity consumption and final energy consumption is taken from ANRE supplied figures for 2015. Years afterward are based on GDP and population growth.

Table 39 Capacity, generation and costs of RES electricity data

RES technologies by capacity (MW)[21]						
	2011	**2012**	**2013**	**2014**	**2015**	**2016**
Wind	822	1,797	2,593	2,809	2,936	2,936
Micro-Hydro	378	427	531	311	326	326
Biomass[22]	25	29	66	100	106	*206*
Solar	1	46	1,159	1,230	1,267	*1,367*

Assumed RES capacity factors[23]	
Wind	0.25
Micro-Hydro	0.28
Biomass	0.78
Solar	0.16

Assumed RES investment costs – CAPEX (€k/MW)						
	2011[24]	**2012**	**2013**	**2014**	**2015**	**2016[24]**
Wind	1,547	1,480	1,462	1,495	1,328	1,336
Micro-Hydro	2,607	2,370	2,222	2,046	1,748	1,586
Biomass	3,509	3,420	3,086	3,022	2,908	2,709
Solar	1,943	1,870	1,344	1,250	1,198	888
Assumed RES investment costs – Fixed OPEX (€/MW)						
Wind	30,500	31,000	29,000	28,000	30,000	28,500
Micro-Hydro	82,000	79,000	34,000	26,000	28,000	-
Biomass	66,500	85,000	108,000	134,000	145,000	169,500
Solar	28,500	26,000	23,000	25,000	18,000	17,500
Assumed RES investment costs – Variable OPEX (€/MWh)						
Wind	11	11	10	10	11	10.5
Micro-Hydro	23	23	10	10	10	10
Biomass	67	62	80	80	70	79
Solar	20	17	10	10	5	5

[21] Note capacity from 2016 onwards is held constant, minus RES technologies assumed to retire after 20-years of operation.
[22] Including Cogen, Landfill/Sewage Gas, and Crops.
[23] Taking the average of 2012-15 Overcompensation Analysis figures. Actual figures from Overcompensation Analyses used for 2012-15.
[24] Linear trend of 2012-15 Overcompensation Analysis figures, held constant from 2016 onward.

A2 EEX and Romanian day ahead prices

Table 40 EEX and OPCOM average day ahead prices by year

	2010	2011	2012	2013	2014	2015
Romanian day ahead price (€/MWh)	36.44	52.13	48.80	35.34	34.66	36.42
EEX day ahead price (€/MWh)	44.13	50.72	42.75	37.61	32.64	31.61
Difference	**-7.69**	**1.41**	**6.05**	**-2.27**	**2.02**	**4.81**

Source: EEX, OPCOM.