Statnett

A European Energy-Only Market in 2030

Analysis report

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Rapport

Sak:

Europeisk energy-only marked i 2030

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Preface

Statnett, the Norwegian transmission system operator, has a long time horizon for planning and operation of the grid. This requires us to understand potential future developments and uncertainties, both in the electricity market and in the power system. Already today, the European electricity market has a significant impact on Nordic price formation. This influence will increase with the additional interconnection capacity that is under construction. In addition, decisions or plans regarding future market design will affect behaviour in today's markets. Analysing the development of the European electricity market is therefore an important basis for our investment analyses and socio-economic analysis for new transmission capacity.

The purpose of this analysis has been to investigate the long-term effects of introducing the energy-only electricity market design in all European countries. The purpose has not been to present a forecast or to give recommendations on the best market design. Model simulations for a 2030 scenario have formed the basis for the analysis.

Karin Lövebrant Västermark, Matthias Hofmann and Emil André Bergmann performed the analysis during the spring and summer of 2015. Anders Kringstad assisted in writing the report. All four work in Statnett's Market Analysis section.

Sammendrag på norsk

Et av de store usikkerhetsmomentene for den framtidige utviklingen av det europeiske kraftmarkedet handler om hvordan perioder med lav fornybarproduksjon blir håndtert. Våre produksjonsserier for sol og vindkraft, basert på 50 års værhistorikk, viser at samlet europeisk produksjon fra sol og vind kan bli svært lav, selv når samlet installert effekt er flere hundre GW relativt jevnt fordelt utover et stort geografisk område. Både det at samlet produksjon kan bli så lav og at det kan ha en varighet på flere dager av gangen er utfordrende og gir et stort behov for fleksibilitet.

Det er liten tvil om at termiske kraftverk vil måtte bidra med mye av den nødvendige fleksibiliteten de neste 10-20 årene. To forhold gjør imidlertid dette til en utfordring:

- Rundt 150 GW termisk kapasitet går ut de neste 20 årene på grunn av levetid og reguleringer
- Det er ikke lønnsomt å investere i ny kapasitet. Dette gjelder spesielt for gasskraft

På bakgrunn av dette har flere land allerede innført kapasitetsmarkeder der tilstrekkelig kapasitet i kraftsystemet blir sikret ved å gi termiske kraftverk og andre tilbydere av effekt nødvendig inntjening utenfor energimarkedene. Alternativet, energy-only, er å la spot og balansemarkedet finne en likevekt uten hjelp av subsidier, men gjerne med en strategisk reserve utenfor det ordinære energimarkedet for å sørge for tilstrekkelig forsyningssikkerhet.

I denne studien har vi analysert de langsiktige konsekvensene av å ha energy-only i alle de europeiske landene. Analysen er basert på simuleringer med vår europeiske markedsmodell[1] og vårt sentrale scenario for 2030, hhv med og uten kapasitetsmarked i alle land. Samlet fornybarandel er på rundt 50 %, på linje med EUs mål for 2030. Hensikten er ikke å gi noen anbefaling av hva som er det beste markedsdesignet for Europa på sikt, men skissere mulige konsekvenser for day-ahead markedet og i hvilken grad energy-only kan fungere rent markedsmessig. Samtidig har vi vurdert mulige konsekvenser for forsyningssikkerheten.

To mulige løsninger – kapasitetsmarkeder eller energy-only

Valg av markedsdesign er sentralt for hvordan de ulike landene møter utfordringene knyttet til lav fornybarproduksjon. Her er det i prinsippet to aktuelle hovedløsninger:

- Kapasitetsmarked: Tilstrekkelig kapasitet i kraftsystemet blir sikret ved å gi termiske kraftverk og andre tilbydere av effekt nødvendig inntjening i et eget marked eller auksjoner utenfor energimarkedene.
- Energy-only: Termiske kraftverk og andre leverandører av fleksibilitet får sin inntjening fra day-ahead- og balansemarkedet alene. Markedet finner selv balansen mellom termisk produksjonskapasitet, bidrag fra forbruksflytting, energilagring og utkobling av forbruk.

En vesentlig forskjell på de to løsningene handler om nasjonale myndigheters kontroll på kapasitetsmarginen i day-aheadmarkedet, det vil si differansen mellom tilgjengelig produksjonskapasitet og forbruket i anstrengte perioder. Med et kapasitetsmarked kan myndighetene kreve at det ikke skal bli reduksjoner i forbruket, selv i de mest anstrengte timene i værhistorikken. Ved energy-only er derimot kapasitetsmarginen[2] utenfor myndighetenes kontroll. I tillegg må den være negativ i anstrengte perioder - forbruk med høy utkoblingspris må av og til gå ut på pris, for at gjenværende kraftverk skal få tilstrekkelig inntjening.

Hvor store markedsmessige forskjeller det blir mellom de to alternativene er i stor grad avhengig av hvordan alternativet med kapasitetsmarkeder blir praktisert. Får vi et lavt krav til kapasitetsmargin fra myndighetene og høy deltagelse fra forbrukssiden i kapasitetsmarkedene blir resultatet relativt likt energy-only. Skjer det motsatte kan forskjellene bli vesentlig større. I vårt 2030 scenario med

[1]Detaljert modellering av Norden, Baltikum, Polen, Tsjekkia, Slovakia, Tyskland, Østerrrike, Sveits, Italia, Frankrike, Benelux og Storbritannia

[2] Differansen mellom tilgjengelig produksjonskapasitet og forbruk

kapasitetsmarkeder har vi lagt inn forutsetninger som gir store forskjeller, i form av solide regionale kapasitetsmarginer, stor termisk produksjonskapasitet og lite forbruksfleksibilitet. Dette har vi gjort for bedre å få fram mulige konsekvenser av å velge det ene eller det andre markedsdesignet.

Energy-only gir færre termiske kraftverk, oftere lastutkobling og flere pristopper

Våre beregninger viser tydelig at vi med energy-only får en kraftig reduksjon i den termiske produksjonskapasiteten, både sammenlignet med dagens situasjon og vårt kapasitetsmarkedsscenario for 2030. Samtidig viser simuleringsresultatene at vi får høyere priser i perioder med lite bidrag fra fornybar kraftproduksjon. Over kortere perioder kan kraftprisene komme helt opp i flere tusen €/MWh, mange ganger høyere enn produksjonskostnadene ved de dyreste kraftverkene. Årsaken til dette er tredelt:

- Dyre gassturbiner må oftere startes opp
- Kapasitet som i dag ikke er i bruk, for eksempel nødaggregater, deltar i spotmarkedet
- Forbruk med høy utkoblingspris går ut i anstrengte perioder

I vårt scenario med kapasitetsmarkeder er simulert lønnsomhet for investeringer i nye gasskraftverk klart negativ når vi kun ser på kraftverkenes inntekter fra spot og balansemarkedet[3]. For å få tilstrekkelig lønnsomhet til både å dekke drifts og investeringskostnader i energy-only scenarioet har vi derfor redusert den samlede termiske produksjonskapasiteten i det modellerte området med 70 GW / 18 %. I lys av de konservative forutsetningene i vårt kapasitetsmarkedsscenario er dette trolig i overkant av hva vi kan forvente. Det er imidlertid liten tvil om at energy-only gir lavere kapasitet i day-ahead markedet. Og sammenlignet med i dag viser våre resultater at de europeiske landene vil få en betydelig reduksjon de neste 10-15 årene, hvis de følger Tyskland og satser på energy-only. Om kapasiteten blir lavere når vi inkluderer eventuelle strategiske reserver er mer usikkert.

Økt satsning på batterier og billige former for forbruksfleksibilitet ser ikke ut til å kunne fjerne behovet for å redusere på forbruk med høye utkoblingspriser, eller ta i bruk andre former for høyt priset fleksibilitet i timene med størst residualforbruk[4]. Selv om vi får høy vekst i bruken av batterier og forbruksflytting, ser vi fortsatt et behov for termiske topplastverk. Og så lenge dette er tilfelle er det nødvendig å ha et visst antall timer per år med priser langt over disse verkenes løpende produksjonskostnader for å sikre nok inntjening. Dette innebærer at forbruk med høy betalingsvilje for elektrisitet må gå ut. Batterier og flytting av forbruk uten store økonomiske konsekvenser kan derfor ikke hindre at det blir korte perioder med ekstra høye pristopper.

Det er et stort potensial for kortvarige forbruksreduksjoner ved høye priser i Europa. Samtidig er det trolig en grense for hva som er akseptabelt, både når det gjelder størrelsen på forbruksreduksjonene, varigheten på den enkelte utkobling og hyppigheten av slike hendelser. I den mest anstrengte perioden i vårt energy-only scenario får vi tre døgn på rad med en samlet reduksjon på 20 000 MW industriforbruk i området modellen dekker. I hvilken grad det er akseptabelt med så store og langvarige reduksjoner er uvisst.

Våre modellberegninger tilsier at det kan gå flere år mellom hver gang prisene blir så høye at industriforbruket reduseres. I gjennomsnitt skjer det kun 20 timer per år. Her er imidlertid utkoblingsprisen for ulike typer forbruk en sentral usikkerhetsfaktor. Vi har lagt til grunn relativt høye utkoblingspriser i intervallet 500 – 8000 EUR/MWh. Antar vi at industrien går ut på lavere priser reduseres pristoppene, men samtidig må hyppigheten øke for at topplastverkene skal ha profitt.

Annen fleksibilitet reduserer kraftverksparken ytterligere og jevner ut prisene

Større kortsiktige prisvariasjoner gjør det mer lønnsomt å investere i andre former for fleksibilitet. I vårt energy-only scenario har vi derfor økt bidraget fra batterier, forbruksflytting og

3 Vår markedsmodell er en spotmarkedsmodell. Vi ser derfor bort fra eventuell ekstra inntjening i balansemarkene i vår analyse

4 Residualforbruket er forbruket fratrukket samtidig fornybarproduksjon

nødstrømsaggregater, basert på beregnet lønnsomhet og tilgjengelig potensial. Tallene angir total kapasitet for hele området dekket av vår modell:

- Batterier: 10 GW / 30 GWh
- Forbruksflytting: 22 GW - 7 % av det gjennomsnittlige forbruket
- Nødstrømsaggregater: 9 GW

Hvor stort bidraget blir fra disse kildene er usikkert. Dette gjelder ikke minst for batterier. Den teknologiske utviklingen går hurtig og det er allerede lønnsomt å investere i batterisystemer for bruk i balansemarkedene på kontinentet. Samtidig viser våre beregninger at det i 2030 fortsatt ikke er lønnsomt kun basert på inntekter fra spotmarkedet. Vi har derfor lagt oss på et konservativt anslag, men ser at volumet kan bli betydelig høyere om kostnadene faller mer enn vi har forutsatt.

Nødstrømsaggregatene har høye driftskostnader og bidrar dermed til flere og høyere pristopper i våre simuleringer. Samtidig ser vi at batterier og forbruksflytting gir lavere prisvolatilitet. Unntaket er i timer der residualforbruket er så høyt at prisen blir satt av topplastverk, nødaggregater eller forbruk med høy utkoblingspris. Den økte fleksibiliteten fra alternative kilder reduserer den termiske kapasiteten ytterligere.

Termiske kraftverk gjør fortsatt hovedjobben selv om alle land har energy-only

Vår analyse viser at selv om hele Europa satser på energy-only, vil termiske kraftverk de neste 15-20 årene fortsatt stå for det klart største effektbidraget når det er lite sol og vind. Dette til tross for lavere installert kapasitet og et vesentlig større bidrag fra forbruksflytting, batterier og forbruksutkobling. I periodene med høyest residualforbruk i våre simuleringer av 2030 scenarioet står termisk kraftproduksjon for over 70 % av det samlede effektbidraget.

Hovedårsaken til det høye bidraget er at det fortsatt er mange kull-, gass- og kjernekraftverk igjen i 2030. Når det gjelder rene topplastverk er samlet kapasitet fra disse mer enn halvert og utgjør bare 20 GW i vårt energy-only scenario. Sammen med tilhørende utkoblinger av industriforbruk, har imidlertid topplastverkene en sentral funksjon som vanskelig lar seg erstatte. Når fornybarproduksjonen er lav over flere dager blir bortfallet målt i energi svært stort. Dette gjør det vanskelig å finne gode alternativer til topplastverk og forbruksreduksjoner. Det vil for eksempel kreve rundt 440 millioner standard husholdningsbatterier[5] hvis det skal være mulig å erstatte bidraget fra redusert industriforbruk og topplastverk i de mest anstrengte periodene i våre simuleringer. Dette vil trolig ikke være lønnsomt. Og ser vi på utviklingen etter 2030 blir behovet for topplastverk enda større etter hvert som mer fornybar erstatter stadig flere termiske grunnlastverk.

Økt nettkapasitet hjelper systemet, men gir begrenset bidrag i de strammeste timene

Modellsimuleringene indikerer at mer nettkapasitet gir en viss utjevning av fornybarproduksjonen. Ved lavere nettkapasitet øker behovet for topplastverk, forbruksfleksibilitet og energilagring. Samtidig viser værhistorikken en betydelig samvariasjon i samlet sol- og vindkraftproduksjon i store deler av det europeiske området. Mer nett reduserer derfor i liten grad toppene i residualforbruket.

Våre resultater tyder på at det ikke er store forskjeller i behovet for overføringskapasitet i et energy-only scenario sammenlignet med et scenario med kapasitetsmarkeder. Utnyttelsen av overføringsnettet øker marginalt, men vi ser ingen signifikant økning i prisforskjeller. Unntaket er mellom Norden og kontinentet der forskjellene øker som følge av flere og høyere pristopper på den kontinentale siden.

Energy-only reduserer forsyningssikkerheten – behov for strategisk reserve

Et framtidig scenario basert på energy-only gir lavere kapasitetsmarginer enn i dag og mest sannsynlig også sammenlignet med et scenario med kapasitetsmarkeder. Dette innebærer at forsyningssikkerheten blir svekket. I hvilken grad energy-only likevel gir god nok forsyningssikkerhet

[5] Vi har her tatt utgangspunkt i en lagringskapasitet på 5 kWh per batteri

er til dels avhengig av hvordan man definerer hva som er tilstrekkelig forsyningssikkerhet. Med noen ytterst få unntak gir modellsimuleringene av vårt energy-only scenario priskryss i alle timer, også i de mest ekstreme værperiodene de siste 50 årene. Det er dermed mulig å hevde at forsyningssikkerheten fortsatt er på et tilfredsstillende nivå. Samtidig er det en del forbruk som må koble ut i timer og dager med høyt residualforbruk. Et system med betydelig lavere margin er også mer utsatt for utfall og feil i nett og kraftverk. Mange vil derfor si at energy-only ikke gir tilstrekkelig forsyningssikkerhet.

Hva som er god nok forsyningssikkerhet er i stor grad et politisk spørsmål og vi kan derfor ikke konkludere på om energy-only gir nok sikkerhet ut fra våre analyser alene. Vi ser imidlertid at den blir svakere og at det blir vesentlig kortere avstand til en situasjon uten priskryss i spotmarkedet når residualforbruket er på sitt høyeste. Det virker derfor fornuftig å ha en strategisk reserve i tillegg.

Energy-only i Europa gir flere og høyere pristopper også i Norge og Norden

Energy-only på kontinentet og i Storbritannia vil påvirke det norske og nordiske kraftmarkedet. Allerede i dag får vi pristopper tilsvarende prisen på kontinentet i timer der tilgjengelig effekt i vann- og kjernekraft ikke er tilstrekkelig til å dekke nordisk forbruk og samtidig gi full eksport sørover. De neste årene forventer vi at dette skjer oftere, som følge av større overføringskapasitet ut av Norden og reduksjoner i svensk kjernekraft. Videre viser våre værdata at de høyeste kontinentale prisene kommer i kalde og nedbørfattige vintre i Norge. Vår vurdering er derfor at energy-only i Europa gir flere og høyere pristopper i Norge og Norden, men at dette ikke skjer like ofte som på kontinentet.

Med flere kortvarige nordiske pristopper på nivå med utkoblingsprisen til industrien på kontinentet kan det hende at også nordisk industriforbruk responderer med forbruksreduksjoner. Utkoblingspriser for norsk industri blir da et pristak i Norge. Hvor ofte dette kan inntreffe er usikkert og avhenger blant annet av investeringer i mer effekt i vannkraftsystemet og andre typer fleksibilitet i Norge.

Sannsynlig med harmonisering mellom land med og uten kapasitetsmarkeder

Det er usikkert hva som blir de langsiktige konsekvensene hvis Tyskland blir det eneste landet med energy-only og kapasitetsreserve, mens resten har kapasitetsmarkeder. Våre simuleringer viser imidlertid at det kan bli betydelige ubalanser om nabolandene har høye krav til kapasitetsmargin og lite forbruk i kapasitetsmarkedene.

- Importen til Tyskland blir svært høy i perioder med lav fornybarproduksjon
- Færre pristopper gir lavere termisk kapasitet i Tyskland enn om alle land har energy-only

En slik situasjon er uheldig både for Tyskland og nabolandene. Tyskland blir avhengig av import og mer sårbar for feil i overføringsnettet. Dette kan gi behov for å øke volumet i reserven. Nabolandene kan på sin side måtte øke egen produksjonskapasitet for å kompensere for manglende investeringssignaler på tysk side. Samtidig er det lite sannsynlig at en slik situasjon kan oppstå. For det første kan Tyskland snu og innføre et kapasitetsmarked likevel. For det andre er det sannsynlig at forbruket deltar i kapasitetsmarkedene. For det tredje kan nabolandene redusere på sine krav til kapasitetsmargin.

Energy-only er mulig, men innebærer utfordringer

En videreføring av energy-only med strategisk reserver ser ut til å være et gjennomførbart alternativ til kapasitetsmarkeder. Et fungerende energy-only marked forutsetter imidlertid følgende:

- Kraftprisen må få lov til å bli svært høy uten fare for innblanding fra nasjonale myndigheter
- Samfunnet må akseptere kortvarige reduksjoner i forbruk med høy betalingsvilje
- Forbruk, spesielt innen industrien, bør ikke skjermes for prisvariasjonene i spotmarkedet
- Når det først er gjort et valg om å satse på energy-only bør dette ligge fast over lang tid

Den kanskje største utfordringen med energy-only er at den langsiktige markedsbalansen mellom etterspørsel og kraftverk er ustabil. Inntjening til topplastverkene er ujevn og avhengig av sjeldne værhendelser. Samtidig kan en kontinuerlig vekst i fornybarandelen, stadig tilbakegang for termisk produksjon og hurtig teknologisk utvikling gjøre at markedet ikke finner noen stabil likevekt. Dette kan gi for lite investeringer i topplastverk.

Summary in English

One of the major uncertainties as regards future development of the European power market relates to how periods of low renewables generation will be handled. Our generation series for solar and wind power, based on 50 years of weather history, show that total European generation from solar and wind can sink to very low levels, even when overall installed capacity is several hundred GW, relatively evenly distributed over a large geographical area. Both the fact that overall generation can sink to such low levels, and that such low periods could last for periods of several days, pose considerable challenges and result in a significant need for flexibility.

There is little doubt that thermal power plants will have to contribute much of the necessary flexibility over the next 10-20 years. However, two factors make this challenging:

- Around 150 GW of thermal capacity will be decommissioned over the next 20 years due to lifetime and regulations
- Investment in new capacity is not profitable, particularly as regards gas power plants

On this basis, several countries have already introduced capacity markets where sufficient capacity in the power system is secured by giving thermal power plants and other capacity providers necessary income outside the energy markets. The alternative, energy-only, is to allow the day-ahead and balancing markets to find an equilibrium without using subsidies, but preferably with a strategic reserve outside the ordinary energy market to ensure sufficient security of supply.

In this study, we have analysed the long-term consequences of having energy-only in all European countries. The analysis is based on simulations with our European market model[6] and our key scenario for 2030, with and without capacity markets in all countries. The total share of renewables in power generation is around 50%, in line with the EU's targets for 2030. The intention of the study is not to provide a recommendation of what is the best market design for Europe in the long term, but to outline potential consequences for the day-ahead market and to what extent energy-only can work in pure market terms. At the same time, we have evaluated possible consequences for security of supply.

Two possible solutions – capacity markets or energy-only

The selected market design is key to how the various countries will meet the challenges related to low renewables generation. There are, in principle, two relevant main solutions:

- <u>Capacity market:</u> Sufficient capacity in the power system is secured by giving thermal power plants and other capacity providers necessary income in a designated market or auctions outside the energy markets.
- <u>Energy-only:</u> Thermal power plants and other suppliers of flexibility will receive their income from the day-ahead and balance market alone. The market itself will find the balance between thermal production capacity, contributions from load shifting, energy storage and load shedding.

A significant difference between the two solutions is related to national authorities' control over the capacity margin in the day-ahead market, i.e. the difference between available generation capacity and the demand during strained periods. With a capacity market, the authorities can demand that there shall be no reductions in demand, even during the most strained hours in the weather history. However, with energy-only, the capacity margin[7] is outside of the authorities' control. It must also be negative during strained periods –high cost load shedding occasionally needs to set the power price, in order for remaining power plants to earn sufficient profits.

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[6]Detailed modelling of the Nordics, Baltics, Poland, Czech Republic, Slovakia, Germany, Austria, Switzerland, Italy, France, Benelux and Great Britain

[7] The difference between available generation capacity and consumption

The extent of market-related differences between the two alternatives largely depends on how the capacity markets alternative will be practiced. If the authorities stipulate a low required capacity margin and a high level of participation from consumers in the capacity markets, the result will be relatively similar to energy-only. If the opposite happens, the differences may be significantly larger. In our 2030 scenario with capacity markets, we included assumptions that could result in major differences, in the form of solid regional capacity margins, major thermal production capacity and minor demand flexibility. We did this to better highlight potential consequences of choosing one or the other market design.

Energy-only provides fewer thermal plants, more hours with load shedding and more price spikes

Our calculations clearly show that, with energy-only, there will be a substantial reduction in the thermal generation capacity, both compared with the current situation and our capacity market scenario for 2030. At the same time, the simulation results show that we achieve higher prices during periods with minor contributions from renewable power generation. Over short periods, the power prices may reach several thousand €/MWh, many times higher than the generation costs at the most expensive power plants. There are three reasons for this:

- Expensive gas turbines must be started more frequently
- Capacity that is not currently in use, for example emergency backup generators, participate in the day-ahead market
- Demand with a high willingness to pay for electricity sheds load voluntary and sets the price in strained periods

In our scenario with capacity markets, simulated profitability for investments in new gas power plants is clearly negative when we only look at the power plants' income from the spot and balancing market[8]. In order to achieve sufficient profitability to cover both operating and investment costs in the energy-only scenario we have therefore reduced the overall thermal generation capacity in the modelled area by 70 GW / 18 %. In light of the conservative assumptions in our capacity market scenario, this is likely in excess of what we can expect. However, there is little doubt that energy-only yields lower capacity in the day-ahead market. And compared with today, our results show that the European countries will have a considerable reduction over the next 10-15 years, if they follow Germany and decide on energy-only. Whether capacity becomes lower when we include potential strategic reserves is more uncertain.

Increased investments in batteries and cheap forms of demand flexibility do not appear to remove the need for reducing demand with high disconnection prices, or using other forms of highly priced flexibility in the hours with greatest residual demand[9]. Even if there is high growth in the use of batteries and load shifting, we still see a need for thermal peak load generators. And as long as this is the case, it is necessary to have a certain number of hours per year with prices far exceeding these generators' long-term marginal costs to ensure a high enough income. This entails that demand with a high willingness to pay for electricity at times must shed load voluntary. Batteries and shifting of demand without major financial consequences therefore cannot prevent the occurrence of brief periods with very high price peaks.

There is a major potential for brief reductions of demand in the event of high prices in Europe. At the same time, there is likely a limit for what is acceptable, both as regards the size of the load shedding, the duration of the individual episodes and the frequency of such incidents. In the most strained period in our energy-only scenario, we have three consecutive days with a total reduction of 20 000 MW industrial demand in the area covered by the model. To what extent such major and long-lasting reductions are acceptable is unknown.

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8 Our market model is a spot market model. We therefore disregard any additional income in the balancing markets in our analysis

9 The residual demand is the demand less renewables generation

Our model calculations indicate that several years can pass between each time the prices become high enough for industrial demand to be reduced. On average, this only occurs 20 hours per year. However, the price for voluntary load shedding for different types of demand is a key uncertainty factor. We have assumed relatively high disconnection prices in the interval of 500 – 8000 €/MWh. If we assume that the industry is based on lower prices, price peaks are reduced, but at the same time, frequency must increase in order for peak load generators to be profitable.

New types of flexibility reduce plant capacity further and even out power prices

Major short-term price fluctuations make it more profitable to invest in other forms of flexibility. In our energy-only scenario we have therefore increased the contribution from batteries, load shifting and emergency backup generators, based on calculated profitability and available potential. The figures indicate total capacity for the entire area covered by our model:

- Batteries: 10 GW / 30 GWh
- Load shifting: 22 GW - 7% of the average demand
- Emergency backup generators: 9 GW

The size of the contribution from these sources is uncertain, particularly as regards batteries. The technological development is rapid and it is already profitable to invest in battery systems for use in the balancing markets in continental Europe. At the same time, our calculations show that it is still not profitable in 2030 based only on income from the day-ahead market. We have therefore used a conservative estimate, but see that the volume could be considerably higher if the costs drop more than we have anticipated.

Emergency backup generators have high operating costs and thus contribute to more and higher price peaks in our simulations. At the same time, we can see that batteries and load shifting result in lower price volatility. The exception is in hours where the residual demand is so high that the price is set by peak load generators, emergency backup generators or demand with a high price for voluntary load shedding. The increased flexibility from alternative sources further reduces the thermal capacity.

Thermal plants continue to do the bulk of the work, even if all countries have energy-only

Our analysis shows that even if all of Europe decides on energy-only, thermal power plants will still be responsible for the clearly largest capacity contribution over the next 15-20 years, when there is little solar and wind. This applies despite lower installed capacity and a significantly greater contribution from load shifting, batteries and load shedding. In the periods with the highest residual demand in our simulations of the 2030 scenario, thermal power generation represents more than 70% of the overall capacity contribution.

The main cause of the high contribution is that many coal, gas and nuclear power plants still remain in 2030. As regards pure peak load generators, total capacity from these has been more than halved and only constitutes 20 GW in our energy-only scenario. Together with voluntary industrial load shedding capacity, however, the peak load generators have a key function that is hard to replace. When renewables generation is low over multiple days, the loss measured in energy becomes very significant. This makes it difficult to find good alternatives to peak load generators and reductions in demand. For example, about 440 million standard household batteries[10] would be required in order to replace the contribution from reduced industrial demand and peak load generators in the most strained periods in our simulations. This will likely not be profitable. And if we look at the development following 2030, the need for peak load generators will be even greater as more renewables increasingly replace thermal base load generators.

Increased interconnection capacity supports the system but has limited effect in the most strained periods

The model simulations indicate that increased interconnection capacity results in a certain balancing of the renewables generation. In the event of lower interconnection capacity, the need for peak load

[10] We have assumed a storage capacity of 5 kWh per battery

generators, demand flexibility and energy storage increases. At the same time, the weather history shows a considerable co-variation in total solar and wind power generation in large parts of the European area. Therefore, more interconnection capacity only yields minor reductions in the peaks in residual demand.

Our results indicate that there are no major differences in the need for transmission capacity in an energy-only scenario compared with a scenario with capacity markets. The utilisation of the transmission grid increases marginally, but we see no significant increase in price differences. The exception is between the Nordic region and continental Europe, where the differences increase as a result of more and higher price peaks on the continental side.

Energy-only reduces security of supply – need for strategic reserve

A future scenario based on energy-only results in lower capacity margins compared with today and most likely also compared with a scenario with capacity markets. This entails that security of supply is weakened. To what extent energy-only still provides adequate security of supply depends, in part, on how adequate security of supply is defined. With a very few exceptions, the model simulations of our energy-only scenario gives price formation in all hours, also in the most extreme weather periods in the past 50 years. One could thus assert that security of supply is still at a satisfactory level. At the same time, some demand must be disconnected for hours and days with high residual demand. A system with a considerably lower margin is also more exposed to outages and faults in grids and power plants. Many will therefore say that energy-only does not provide sufficient security of supply.

What constitutes adequate security of supply is largely a political question and we therefore cannot conclude whether energy-only provides sufficient security based on our analyses alone. However, we see that it will be weaker and there will be a significantly shorter distance to a situation without price formation in the day-ahead market when the residual demand is at its highest. It therefore seems sensible to have a strategic reserve in addition.

Energy-only in Europe results in more and higher price peaks also in the Nordic region

An energy-only market design in continental Europe and Great Britain will impact the Norwegian and Nordic power market. Even today, there are price peaks corresponding to the price on the Continent during hours where available capacity in hydropower and nuclear power is not sufficient to cover Nordic consumption and also provide full export southward. Over the next few years, this is expected to happen more frequently, as a result of greater interconnection capacity going out of the Nordic region and reductions in Swedish nuclear power. Furthermore, our weather data shows that the highest Continental prices come during winters in Norway that are cold and have little precipitation. Our assessment is therefore that energy-only in Europe results in more and higher price peaks in Norway and the Nordic region, but that this does not happen as frequently as on the Continent.

With more and shorter Nordic price spikes in line with the price for voluntary industrial load shedding on the Continent, Nordic industrial demand could in turn respond with load shedding. The price for voluntary load shedding for Norwegian industry will then become a price ceiling in Norway. How often this can occur is uncertain and e.g. depends on investments in more capacity in the hydropower system and other types of flexibility in Norway.

Harmonisation between countries with and without capacity markets is probable

The long-term consequences are uncertain if Germany becomes the only country with energy-only and capacity reserve, while the rest have capacity markets. However, our simulations show that there could be considerable imbalances if the neighbouring countries have high requirements for capacity margin and minor amount of demand in the capacity markets.

- Import to Germany will be very high during periods with low renewables generation
- Fewer price peaks result in lower thermal capacity in Germany than if all countries have energy-only

Such a situation is unfortunate for both Germany and the neighbouring countries. Germany will be dependent on import and more vulnerable to outages in the transmission grid. This could necessitate increasing the volume in the strategic reserve. The neighbouring countries may have to increase their own generation capacity to compensate for lacking investment signals from the German side. At the same time, it is not probable that such a situation can occur. Firstly, Germany can still reconsider and introduce a capacity market. Secondly, it is probable that consumption will figure into the capacity markets. Thirdly, the neighbouring countries can reduce their requirements for capacity margin.

Energy-only is a feasible but challenging market design option

A continuation of energy-only with strategic reserves looks to be a feasible alternative to capacity markets. However, a functioning energy-only market presumes the following:

- The power price must be allowed to become very high without the risk of intervention by national authorities
- Society must accept brief reductions in consumption with a high willingness to pay for electricity
- Consumption, particularly within the industry, should not be shielded from the price fluctuations in the spot market
- When a decision has been made to go for energy-only, this should stand firm for a long period

Potentially the greatest challenge associated with energy-only is that the long-term market balance between demand and power plants is unstable. The peak load generators' income is unbalanced and depends on rare weather incidents. At the same time, a continuous growth in the renewables share, continuous decrease of thermal generation capacity and rapid technological development, can result in the market not finding a stable equilibrium. This can result in too few investments in peak load generators.

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Terms used

Capacity margin	In this analysis, we define the capacity margin as the difference between generation capacity available to the market, plus the available imports and less the demand. We define the capacity margin to be zero just prior to the point of voluntary load shedding.
Capacity market	In this market design, market actors are paid for supplying generation capacity during a given period. The capacity is normally traded in an external market, outside day-ahead and balancing markets.
CCGT	Combined Cycle Gas Turbine. A plant that combines both a gas turbine and a steam turbine and thus achieves a higher power efficiency than an open cycle gas turbine (OCGT). Normally commissioned for base load generation.
Energy-only market (EOM)	In this market design, market actors generate their income through trade in the day-ahead and balancing markets only. There is no separate market for trading of capacity.
Load factor	The load factor explains the average utilization of a power plant over a certain period. Defined as average load divided by peak load in a specific period. Usually expressed in hours or in relative terms.
OCGT	Open Cycle Gas Turbine. A typical power plant commissioned for peak load generation.
Residual demand	Total power demand less renewable energy generation.
Security of supply	Throughout this analysis, the day-ahead market provides secure supply as long as it forms a price in each hour. This applies regardless if some demand opts to shed load at high prices.
Weather series	Our hourly generation and demand series for the historical weather period of 1962–2012. For more info, see Box 1.

1 Renewables and the challenge of backup capacity

The European power sector is undergoing a major restructuring process, where the central driver is the need to decarbonise. The increasing share of renewable energy brings several challenges. One challenge is that aggregated renewable generation can become very low. The larger amount of generation from renewables will only slightly reduce the need for flexible backup capacity. Another challenge is reduced income and unprofitability for thermal power plants.

How the European countries balance the need for secure electricity supply against the need for more renewable energy is therefore a key question. In particular, European countries will have to decide on whether to leave the stimulation of new investments in flexible capacity to the existing energy-only market or to bring it into a separate capacity market.

Higher share of renewables requires larger amounts of flexible capacity

EU member states have committed to increase the share of renewables in the energy mix to 20 % by 2020 and to 27 % by 2030[11]. As a result, many European countries subsidise renewable generation capacity into the electricity market. By 2030, we estimate around 250 GW wind power and 200 GW of solar power in the European power system[12]. This equals a renewable generation of 800 TWh per year and a 50 % share of total European electricity generation.

Renewable power generation is by nature intermittent, and we have seen in our historical weather series that the variation in generation often correlates over large parts of Europe. Periods of low aggregated renewable generation will be a challenge for the power system, especially considering the massive expansion of renewable generation capacity in the coming years. Figure 1 portrays an extreme example. Here, generation from renewables is considerably below average generation levels for almost an entire month. The case is one of the worst in our historical weather series, but we see shorter periods with low renewable production every winter. Although wind power normally has the highest load factor in winter, solar power generates at a minimum due to the low position of the sun.

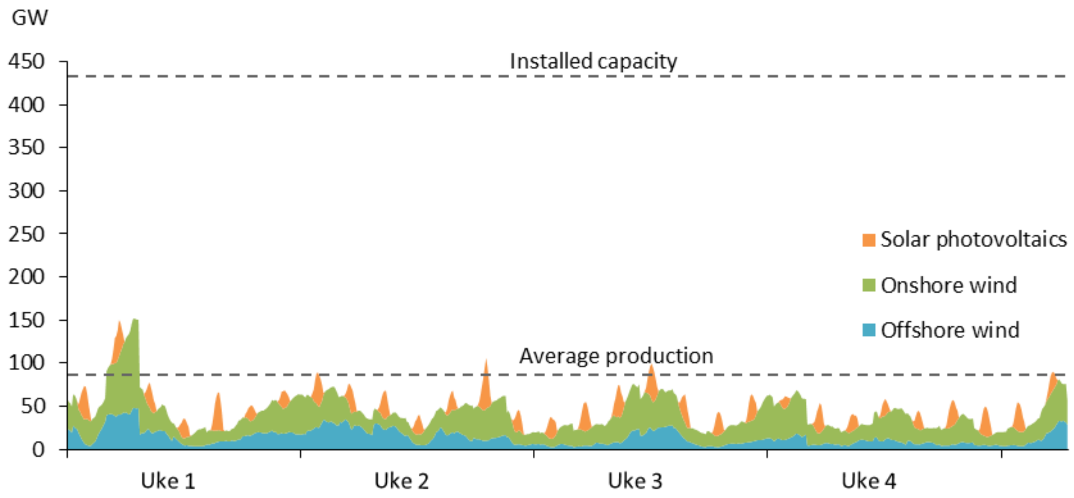

Figure 1. Aggregated generation from wind and solar power in most of Europe for one month of historical weather patterns with the installed renewable capacity in our 2030 scenario.

[11] European Commission 2015

[12] Our model includes most of the countries in Europe, excluding Spain, Portugal, Ireland, and East-European countries east of Austria, Slovakia, Poland and the Baltic states

Box 1. Historical weather series show large fluctuations in generation from wind and solar PV

Historical weather series are an important part of our analysis. Experts on meteorological models at Kjeller Vindteknikk have calculated synthetic time series for hourly generation from solar PV, onshore and offshore wind power for each European country, based on historical weather for 51 years (1962–2012).

Our weather series show that aggregated generation from wind and sun can be low – both over a large geographical area and for several days. Figure 2 illustrates renewable generation in an hour, day or week relative to average generation, for the majority of Europe in our scenario for 2030. Total European generation of renewables can fall close to zero in periods of one hour. Generation can also be low for longer time periods. Minimum daily generation is around 15 % of average daily generation and weekly around 35 %. It is important to note that 35 % of average generation is still low. It corresponds to below 10 % of installed capacity.

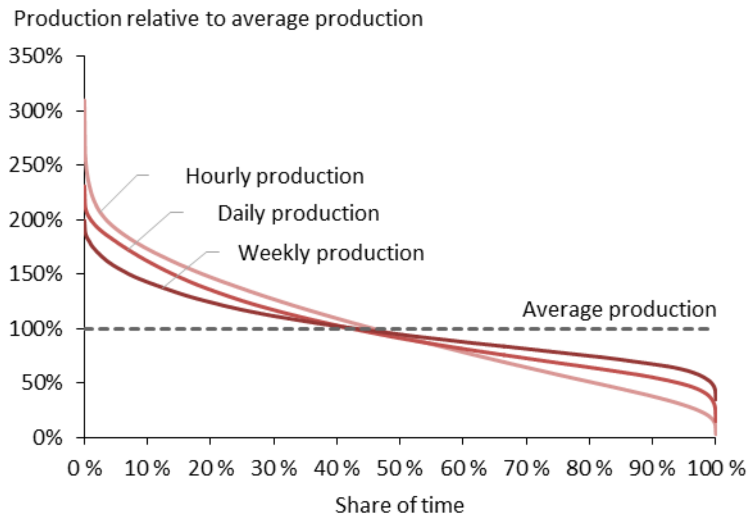

Figure 2. Aggregated European solar and wind power production can become very low on an hourly, daily and weekly basis.

In addition to wind and solar generation, hourly national demand and weekly hydropower inflow are modelled with historical weather series in our simulations. When we refer to our weather years in this analysis, we thereby mean the generation and demand patterns, as they would have varied with the weather in the 51 historical years 1962–2012.

The amount of flexible capacity that is needed to receive a price in the day-ahead market, at any given time, does not just depend on fluctuations in renewable generation, but also on variations in demand. In this analysis, we refer to the combined effect of demand and renewable production as residual demand. The definition for residual demand is the total power demand less power contributed by renewable energy sources.

For most of Europe, electricity demand is at its highest during cold winter periods. Our historical weather series show correlation between temperature and wind power output. Wind generation is usually at low levels during very cold periods, resulting in high residual demand.

In Figure 3, we compare the duration curve for residual demand in today's Europe with that of our assumptions for 2030. We see that the great increase in renewable energy shifts the curve considerably downwards. This means that, in general, there is less need for energy from thermal plants. In a few hours, renewable generation even exceeds demand. However, even with a significant amount of renewable energy, there will still be some hours with very high residual demand and accordingly, a need for flexible backup capacity. In these hours, the residual demand is only 7 % lower in 2030 compared with 2014.

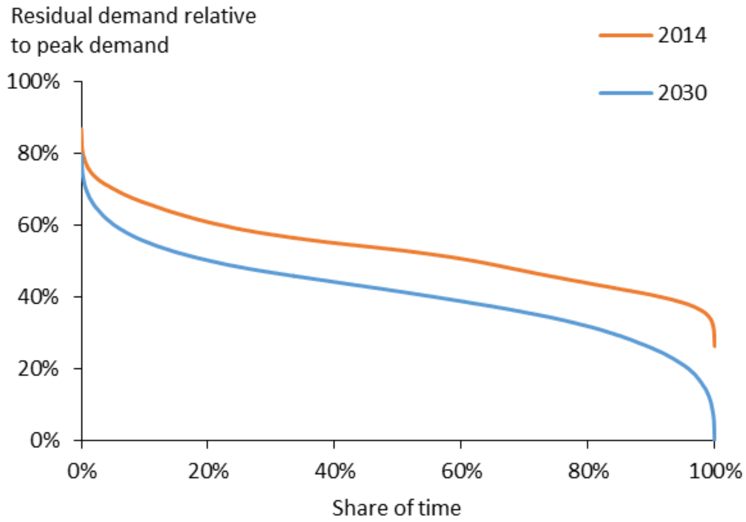

Figure 3. Residual demand in Europe decreases in general with increased renewable power generation in 2030, but hours with very high residual demand nonetheless remain.

There are several possible options for meeting the challenge of periods with high residual demand. The main alternatives are:

- Backup in the form of thermal power generation capacity
- Increased demand flexibility (load shedding and load shifting)
- Increased use of energy storage systems
- More interconnection capacity

We believe demand flexibility will become more important in the long term, but that there is a limit to the potential. Thermal power plants will continue to play a key role, particularly in the next 15-20 years. As we will see later, this applies regardless of the chosen market design.

Thermal power capacity is on the decline – investments in this capacity unprofitable

The increased share of renewables has a significant impact on the electricity market. With a marginal cost close to zero, renewables contribute a substantial amount of energy into the market and reduce the general wholesale price level. Thermal power plants will therefore experience reduced operating hours and receive lower income for their generation. Among the worst affected are peak load generators, which have seen operating hours and income almost completely diminished for the last couple of years. The investment outlook for thermal capacity in the European electricity market is therefore highly uncertain.

Today, many European countries have a great surplus of generation capacity. However, during the coming 20 years, approximately 150 GW of thermal capacity is likely to be decommissioned. This is due to reaching the end of lifetime and/or environmental regulations. Because of strong climate policies, we do not expect new investments in coal or lignite power plants after 2020. Investments in new gas power plants to date have not proven to be profitable.

All the same, Europe will need to invest in flexible generation capacity in addition to the renewables. A challenge for the future electricity market, regardless of design, is therefore to ensure security of supply at all times, and simultaneously secure the profitability of the needed backup generation and flexibility. Because the electricity market of today gives only weak investment signals for thermal backup generation, European countries are discussing different electricity market designs to ensure an adequate level of thermal production capacity.

Capacity markets and energy-only markets are options for future market design

Capacity markets and energy-only markets are two different options for future market design. While energy-only markets are the common market models of today, some countries have introduced capacity markets in addition. Capacity markets can have different designs and may include auctions, certificates or outright investment subsidies. The common element is that the actors receive payments for providing capacity during a given period. An ideal capacity market provides payments to any supplier of capacity: power plants, consumers, storage facilities or interconnectors. The point is to provide adequate revenue for the market participants to ensure sufficient security of supply. It is up to national authorities to decide on the minimum level of capacity margin. All capacities can still participate freely in the day-ahead market and generate income there. The day-ahead market will partly lose its function to generate power plant investments, and mainly fulfil the function of securing dispatch.

In an energy-only market, the day-ahead market fulfils both the function of securing a rational dispatch and the function of generating long-term investments. Power producers and other suppliers of flexibility generate their income through trade in the day-ahead and balancing markets. This market design leaves it up to the market to find the necessary amount of flexible capacity to cover variations in residual demand. National authorities cannot control the capacity margin or the existing generation portfolio. A functioning energy-only market will theoretically require periods with a capacity margin below zero, which means periods where load shedding sets the price. To maintain operational security, it is possible to combine the energy-only market with a strategic reserve. That enables national authorities to decide on the amount of reserves for strained situations. However, the capacity included in the strategic reserve cannot participate in the day-ahead market. It will only be applied in cases where the market fails to balance supply and demand on its own, that is, when the supply and demand curve does not intersect without rationing.

Several European countries have declared their long-term plans and ambitions regarding market design. Still, there is considerable uncertainty around how the European day-ahead market will work 10-20 years from now. Several countries have introduced capacity markets, and more are planning to do so. One example is the UK, which held its first capacity auction in December 2014, for delivery in the winter 2018/19. However, during the past year both the European Commission and individual countries (e.g. Germany) have declared scepticism towards introducing capacity mechanisms. According to the ongoing decision process in Germany, the country will most likely decide on an energy-only market with a strategic reserve[13].

[13] As published in the recent White paper (Bundesministerium für Wirtschaft und Energie 2015)

2 Our analysis – scope and approach

Our reference scenario for 2030 assumes there are national capacity markets. However, given the uncertain future development of European market design, we also find it important to explore an energy-only market scenario. In this study, we have investigated both a case where all of Europe has an energy-only market and a case where Germany is the single energy-only market. The purpose has been to investigate what consequences these cases would have for the European day-ahead market and, on a high-level, for security of supply. The intention has not been to give any recommendation on the best or most efficient future market design.

Market simulations and literature studies form the core of the analysis

We have based our analysis mainly on simulations with the BID market model and our underlying dataset. BID is a fundamental market model and our dataset includes nearly all of the European electricity market[14] with power plants, electricity demand and interconnection capacities between countries. The time resolution of the market model is one hour. We have simulated our 2030-scenarios over a range of 51 historical weather years, using our historical weather series[15]. A robust energy-only market will need to handle substantial deviations in renewable generation and demand, so it is important to study a large range of possible weather situations. Model simulations enable us to understand the fundamental dynamics in the different cases. At the same time, we believe it is important to ensure that the model results are always validated, and that they are put into context.

We do not consider stochastic events, such as unforeseen outages of power plants or transmission lines, in our market simulations. In reality, such events can have severe consequences as regards capacity margins, power prices and, ultimately, security of supply. The Polish power system recently experienced such a situation, when power producers had to cut power production due to a heatwave, and large industrial consumers experienced forced power cuts (Financial Times, 2015). We have not taken such extreme events into account in our analysis. The results of the analysis are still credible and provide a trustworthy general picture.

We base our assumptions on potential for and cost of different system flexibilities on an extensive literature study. The literature review started with the German expert reports, which formed the basis for the ongoing decision on future market design in Germany[16]. In addition, we have used other publications and scientific papers on potential for and cost of demand side response and other flexibility options in specific European countries and on a European scale[17].

Two simplified scenarios for market design – share assumptions for other development

The base case in this study is our reference scenario for 2030. In the reference scenario, we assume capacity mechanisms in all European countries. There is no rationing of demand and the capacity margin is large enough to cover residual load at all times, reflecting risk averse national authorities and regulators. The base case includes little explicitly modelled demand side flexibility.

In the energy-only market scenario, we assume that market actors are profitable purely through trade in the day-ahead market. The size of the capacity margin is a consequence of the market balance, and is considerably reduced as compared to the base case (the scenario with capacity markets). The energy-only scenario includes explicit modelling of several types of system flexibilities.

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[14] Detailed modelling of the Nordics, Baltics, Poland, Czech republic, Slovakia, Germany, Austria, Switzerland, Italy, France, Benelux and Great Britain

[15] For information about our weather series, see Box 1.

[16] r2b 2014, Frontier economics and Formaet Services 2014

[17] Paulus and Borggrefe 2009, BET 2013, dena 2010, Agora Energiewende 2013, Gils 2014, sia partners 2014, Capgemini 2008, ewi 2012

The scenarios are simplified when it comes to implementation and practice of the two different market designs. It is possible to implement a capacity market in a way that largely resembles an energy-only scenario. All the same, we have chosen to use two simplified cases to better illustrate possible consequences for the market.

The scenarios share most of the underlying assumptions for the development towards 2030. We assume the EU will reach its climate and energy targets of 40 % reduction in emissions and 27 % share of renewables by 2030. To reach the targets, we expect the share of renewable energy in the power sector to grow from 20 % today, to around 50 % in 2030. We expect aggregated European electricity demand to grow slightly from today to 2030.

Even with a considerable increase of renewable generation capacity, we anticipate thermal power to be price setting in most hours also in 2030. Costs of coal, gas and CO_2 are therefore important factors for power price formation. We assume short run marginal costs for coal power to be lower than for gas in 2030, but with less coal in the generation mix, gas power will have the greater impact on price levels.

Defining security of supply and capacity margin within this analysis

Security of supply and capacity margin are both terms that have a multitude of definitions and aspects. It is important for us to explain what we mean with the terms, in order to clarify our analysis results. The definitions below are what we find to be the most useful way to describe the terms within the scope of this analysis. The definitions are not an official Statnett view, and we are aware that there are several important facets of the two terms.

From a day-ahead market perspective, we may consider situations where high prices cause consumers to shed load (typically power intensive industry) to be violations of secure supply. On the other hand, we could also argue that there is security of supply as long as there is price formation in the day-ahead market and no sudden blackouts. Within this analysis, we look at security of supply mainly though that second perspective. The market must have an ability to form a price in each hour, but it does not need to cover all demand that has a price for what we can describe as voluntary rationing.

Capacity margin is a measure of the adequacy in the market and is in our analysis defined as available generation and transmission capacity less demand. Strictly speaking, for each hour, it is the difference between generation capacity available to the market, plus the available imports and less the demand. Activation of price elastic demand, as in the energy-only scenario of our analysis, makes it more challenging to measure the capacity margin. We therefore define the capacity margin to be zero just prior to the point of voluntary load shedding at a price higher than the most expensive production units in the system. In the case where load shedding is required to ensure price formation, this analysis defines the capacity margin as negative.

Calculation of the profitability of market participants

Whether different units participating in the market are profitable or not is a key question in our study. When we calculate the profitability of a participant, we use the results from market simulations as revenue stream. A broad literature review is the foundation for our cost assumptions for different technologies. We assume a minimum average internal rate of return of around 10 % for thermal plants.

The model simulations are only snapshots of the power system in the year 2030. We base the profitability calculations on the income and cost of that snapshot year, although it is the average over 50 simulated weather years. In reality, the power system is in a state of continuous change and this will influence real calculations and assessments of profitability of new investments. The calculations do not directly consider this development, but still provide a good indication of expected profitability.

Figure 4 is an example of profitability results and illustrates the profitability of thermal power in our reference case, based only on day-ahead market trade. Most thermal technologies are far from profitable for both operation and investment in this scenario (that presupposes capacity mechanisms).

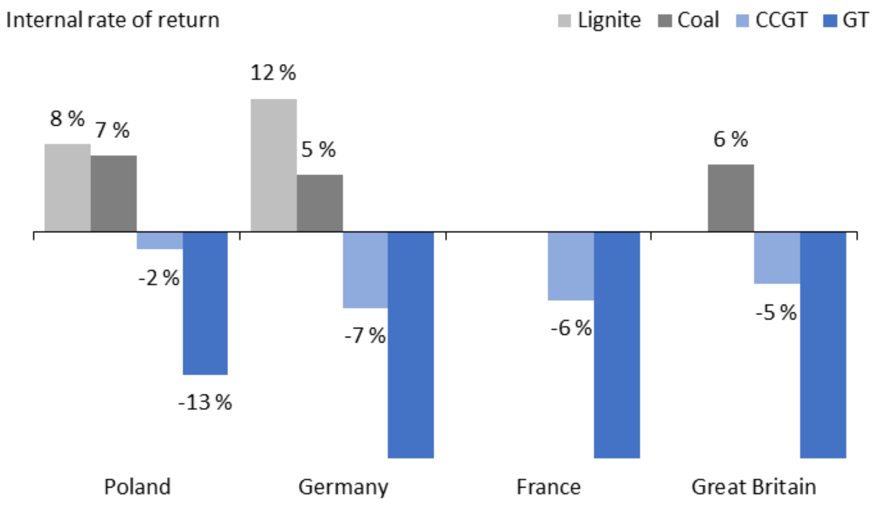

Figure 4. Profitability of thermal power plants with income only from the day-ahead market in our reference case for 2030 (reference case assumes capacity markets).

Work process of designing the energy-only market case in 2030

We have constructed the energy-only market scenario through a stepwise approach, starting with our original reference case for 2030. Through addition of estimated amounts of flexibility and iterative removal of unprofitable thermal power plants, we managed to create a case based on long-term market balance between demand and supply.

- The operation of all power plants is profitable based solely on day-ahead market income[18]
- New investments in peak power plants receive an internal rate of return of at least 10 %
- Incorporated system flexibilities are profitable without subsidies

Renewable energy technologies are not required to be profitable, because we assume sufficient support schemes will still be available in 2030.

[18] Our market model does not cover the balancing markets. This means that we are not able to calculate the possible additional revenue from participation in these markets. The real overall revenue of power plants is therefore somewhat underestimated in our analysis.

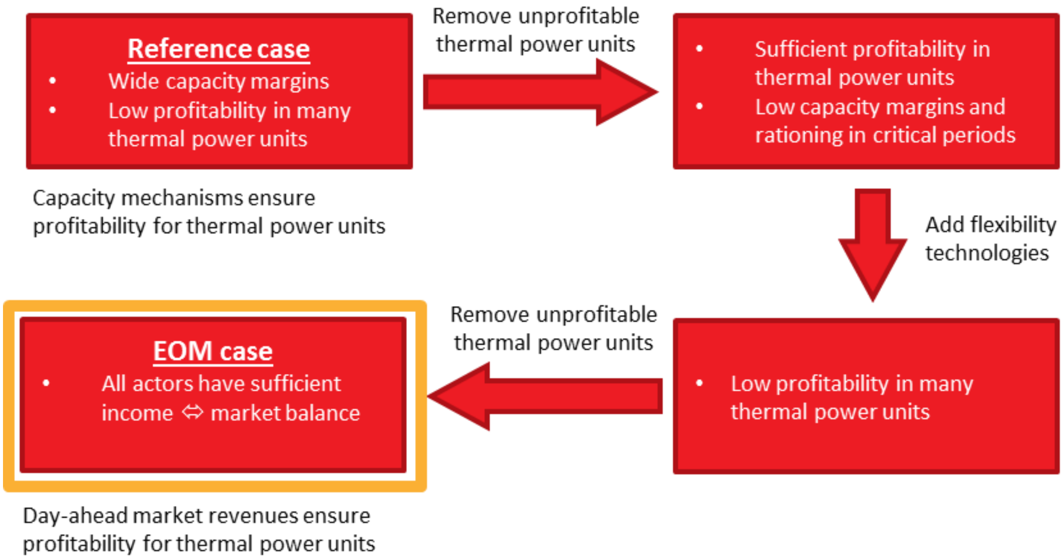

Figure 5. The energy-only market case (EOM) is constructed through a stepwise approach of adding flexibility technologies and removing thermal production units until prerequisities are fulfilled.

Uncertainties in model, data and assumptions

All underlying scenario assumptions are associated with uncertainty. This includes investment and operational costs, technology development, potential of system flexibilities, fuel costs, required rates of return, etc. This is impossible to avoid, but can be handled by sensitivity analysis and good understanding of the different drivers and relationships in the market. One example of such an uncertainty is the level of future power prices. The power price is higher in our 2030 scenarios than it is today, mainly because we expect gas and CO_2 prices to rise until 2030. We know that most of our results are robust to changes in power price levels. Only a few factors, such as profitability of batteries, depend on this. Overall, modest changes in price levels will therefore not affect the main conclusions of the analysis.

There is also uncertainty around structuring and implementation of different market designs, such as requirements relating to capacity margins and risk aversion for investors to invest in flexibility technologies. In addition, a market model in itself always has limitations and weaknesses. The results of the simulations thus require careful interpretation.

Both our reference scenario and the investigated energy-only scenario are two simplified examples of possible solutions to the depicted challenge. In our reference scenario, thermal backup generation is the exclusive solution to maintaining security of supply and adequate capacity margins. The energy-only market scenario is a distinct contrast to this. In this sense, the simulations lead to exaggerated differences between the two solutions. In reality, the authorities could ease their restrictions on minimum capacity margins in a capacity market scenario compared to what our reference scenario assumes. At the same time, flexibility technologies could enter the capacity market due to profitability and help to ease tight capacity margins. Overall, this means there might be more nuanced solutions to the future challenges.

Thus, the analysis does not provide perfect answers as to how a power system with the different designs would look and behave. At the same time, we are confident that the simulations and our interpretations, overall, provide reliable indications of the difference between the two cases, and shed light on the most important issues and questions in the further discussion.

3 Potential and role of system flexibilities

A well-functioning energy-only market will require a diverse supply of flexible capacity to balance the fluctuations in residual demand. Conventional thermal power will most likely represent the major capacity contribution, but other types of flexible capacity will also contribute. One reason for this is that the increased volatility of power prices in an energy-only market incentivises investments in load shifting and energy storage facilities. Another reason is that the increased exposure to high prices will make consumers bid more actively in the market, and during periods of high prices, consumers would rather shed their load than accept price spikes.

An active demand side is necessary in an energy-only market. It is necessary that demand, in strained periods, sets the power price in order to make it possible for peak thermal capacity to recover investment costs based on revenues from the day-ahead and balancing markets alone. In addition, an active demand side is necessary in safeguarding price formation and thus security of supply. An energy-only market certainly gives lower capacity margins in the day-ahead market than the alternative with capacity markets.[19] Having an available potential of load shedding (willingness to voluntarily reduce demand at certain price levels) is crucial to ensure adequacy in all situations. Seen from the alternative perspective, consumers will also mitigate their own market risk by becoming more flexible. In contrast to load shedding, the other system flexibilities investigated throughout this analysis are not absolute necessities in order for an energy-only scenario to function. However, all flexibilities help to balance the variations in residual load.

The potential for flexibility in Europe is large enough to fulfil the need in our energy-only scenario. The large portfolio of existing industries spread across Europe has a substantial potential to participate more actively in the day-ahead market. Battery storage units already participate in the balancing markets, and the expected technology development will lead to further improved conditions. New technology will make both domestic and industry load shifting more accessible and easy to implement.

Load shedding sets the price in critical situations

Load shedding is important in the functioning of an energy-only market. It provides two key elements:

- It supplies an extra buffer capacity that can be used in situations with very strained margins
- It allows peak generating capacity to recover investment costs from the day-ahead market

Compared with the alternative of capacity markets, a system based on energy-only certainly gives lower capacity margins in the day-ahead market. The size of the difference depends on the requirement for capacity margin in the capacity market scenario. With energy-only, the power price is determined by the price of load shedding in periods of high demand and low renewable generation. Figure 6 exemplifies a situation where the generation capacity available to the market is insufficient to meet the demand. Without price-sensitive demand, and a voluntary load shedding potential, rationing and violation of security of supply would occur in this situation.

In a system with a positive capacity margin, thermal peak-load plants usually determine the power price when activated, and thus seldom receive a surplus high enough to recover long-term costs. In order to make a profit without subsidies, it is therefore necessary to have periods where the power price is higher than the short-term marginal cost of these plants. This implies a negative capacity margin and that the power price is set by the price of load shedding in strained situations.

[19] The overall difference in capacity margin is more uncertain and depends on whether the alternative involving energy-only is combined with a strategic reserve, and the size of this.

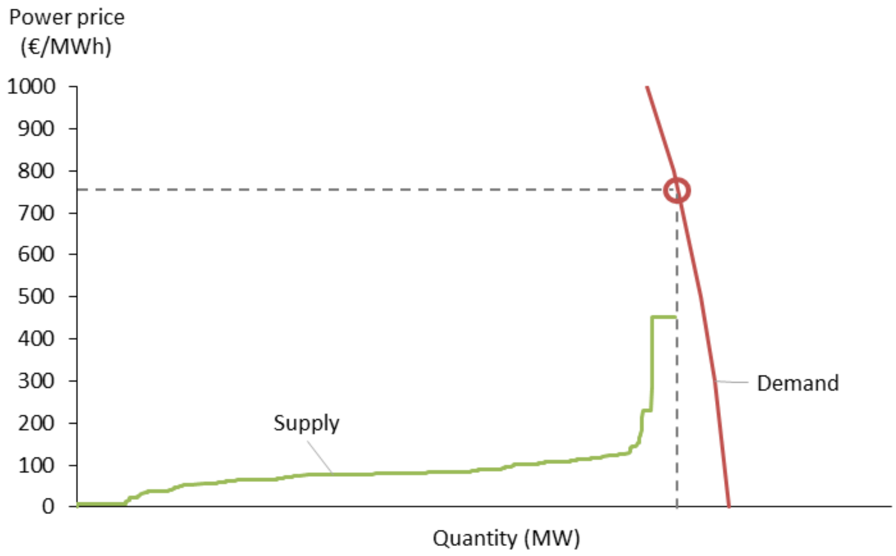

Figure 6. Demand can set the power price in critical situations, if demand is price-sensitive and can shed load.

Among demand-side participants, the power-intensive industry has a large potential for reducing its electricity demand over shorter periods. The industry also has the possibility to deliver critical load shedding over longer periods, such as an entire day or week. In addition, with smart metering and more exposure to the wholesale power price, the residential and commercial sectors can make a substantial contribution. However, it is uncertain how much and at what price these sectors can contribute.

The cost of load shedding in industrial processes is determined either by the cost of alternative energy supply or by the profit margin. For most industrial processes, these costs will be higher than the marginal cost for the most expensive power plant. Industry with high electricity consumption has a limited willingness to pay for electricity, typically several 100 €/MWh, whereas other industry has a higher value of electricity of up to several 1000 €/MWh[20]. The cost of load shedding can be both higher and lower for households and commercial services and is dependent on the comfort loss and the loss of working hours. Combined with a lack of statistical empirical data on the consumer's willingness to pay, in a situation with both access to smart meters and exposure to wholesale prices, the cost value is highly uncertain from this type of consumption. The values can range from 100 €/MWh to over 10 000 €/MWh.

If all the demand is price-elastic, there will always be enough load shedding potential available to balance demand with generation in the day-ahead market. If prices are high enough, both industrial and domestic consumers will reduce their demand and thus ensure price formation in the market. The question is whether the required level of load shedding, both in terms of total capacity and length of shedding period, is within a level that is acceptable to society. In addition, the overall available volume for load shedding is uncertain.

Load shifting evens out variations in residual demand

Load shifting is another way for the demand-side to participate in the electricity market. A consumer may shift its electricity demand by moving consumption from one point in time to another. In contrast to load shedding, the electricity demand has to be recovered after a given time period. A consumer could, for example, increase the electricity demand upfront in order to reduce electricity consumption later on, or vice versa. Figure 8 illustrates the difference between load shedding and load shifting.

[20] r2b 2014, Frontier economics and Formaet Services 2014, OFGEM and Department of Energy & Climate Change 2013, ewi 2013

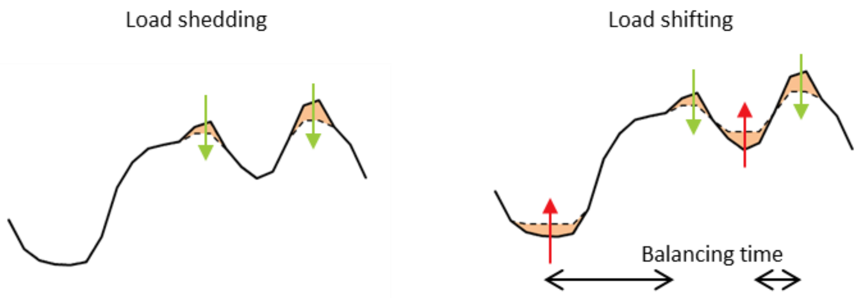

Figure 7. Illustration of the load shedding and load shifting concepts for a 24 hour demand curve. .

Load shifting will help to balance demand and supply by moving demand from the peak to hours with less demand. Normally, the duration of a shift is limited. Depending on the cost, load shifting may happen every day or only in very strained periods. Nevertheless, the shifting of load will contribute to security of supply, as it will reduce the peak demand.

The cost of load shifting may vary substantially depending on the kind of load shifted, from nearly zero to near the level of load shedding. Load shifting has a marginal cost linked to the consequences for the user group that shifts its demand. Heating and cooling processes are good examples of possible load shifting processes, as they normally include some kind of heat or cold storage. As long as temperatures are kept within a tolerable level, the cost of shifting the electricity demand is close to zero. Other users, such as industry, can have higher shifting costs because they must recover production at a later point in time at a higher production cost. Thus the cost of shifting in industrial processes can range from around 10 €/MWh to 100 €/MWh[21].

Significant potential for both load shedding and shifting in Europe

We know that demand-side flexibilities are already available in today's electricity market, but a key issue is whether there is enough flexibility available to have a well-functioning energy-only market in 2030. Our simulations show that sufficient load shedding potential is a prerequisite. There is no absolute dependency on other system flexibilities; however, the existence of other system flexibilities will help balance the variations in residual load.

The potential for the different flexibility technologies is significant, but has different characteristics. Shedding and shifting of load is dependent on the underlying industrial or household processes and the related costs of utilizing this potential. Energy processes suitable for shifting are typically:

- Heat or cold storage (e.g. space heating, refrigerators)
- Physical storage (e.g. cement industry)
- Flexible usage (e.g. washing)

The usage of the flexibility within these processes is constrained either by technical requirements or by loss of comfort or income. Some processes can be shifted several times a day and others more seldom. The duration of the shift is normally dependent on storage capacity, but in processes that lack storage, loss of comfort sets the limit.

Several companies already apply load shedding and load shifting in European electricity markets today. The Belgian company REstore has more than 1 GW of peak load from more than 80 industrial customers under management.[22] Two examples of their customers are ArcelorMittal, a steel producer, and Barclays, a bank. REstore participates with this flexible load in the English and Belgian balancing markets. As much as 350 MW is available at 95 % of the time and can be used on a daily basis. All the

[21] BET 2013, dena 2010

[22] Greentech Media 2015

load under management is flexible and REstore can operate the customer's demand on short notice. In Germany, the company Entelios participates in the balancing market with an aggregated demand response portfolio.[23] Examples of companies they have as customers include a brewery and a paper mill. Both REstore and Entelios focus on industrial and other large consumers when they aggregate their demand response portfolios. In the future, smart meters and other technology improvements may make it more interesting to include households and smaller business units as well.

Numerous reports and analyses investigate the potential of demand-side flexibility in the current and future power system. Figure 8 provides an overview of the estimates of the available flexibilities in the different reports. These analyses estimate that around 10 % of the average electricity demand is likely to be flexible and able to participate actively in the power market. However, the estimates are uncertain and range from 6 % to 19 %. In our energy-only scenario for 2030, we assume that 13 % of the demand is flexible, with 5.5 % load shedding 7.5 % load shifting.

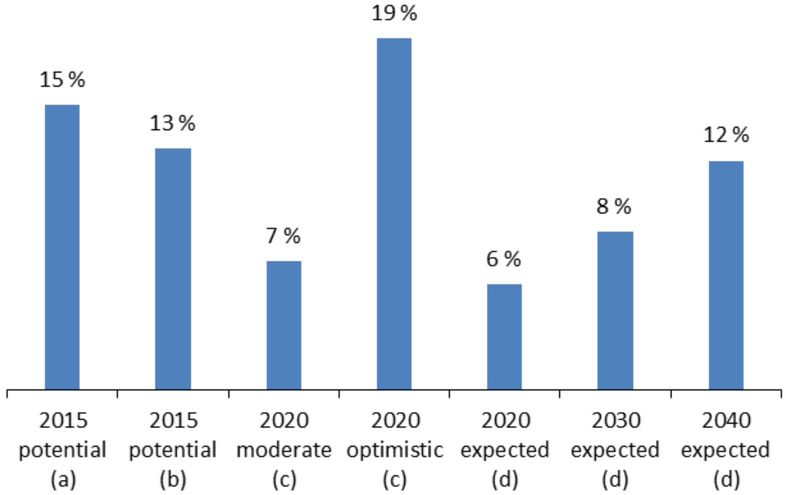

Figure 8. Demand response in Europe in % of average electricity demand in 2030. Summary from different sources (a – Gils 2014, b- sia partners 2014, c - Capgemini 2008, d – ewi 2012).

Emergency backup generators are a cheap source of flexibility

Emergency backup generators are a flexibility option that may play a more important role in a future energy-only market. The traditional purpose of this kind of generator is to deliver emergency power to a critical consumer in the case of a power interruption. Hotels, hospitals, airports and banks are typical examples of consumers that maintain emergency backup generators. It is possible to bid this generation capacity into the electricity market without violating security of supply for the consumer that has the generator. If a power interruption occurs while the generator is under operation, automatic controls ensure that it enters into island operation for its critical consumer.

The advantage of emergency backup generators is the low cost of making them available in the electricity market. It is the demand for secure electricity supply that drives investment in backup generators. The generator does not have to make itself profitable by profits from the electricity market. The additional cost of equipping emergency backup generators with the possibility to react to price signals is quite low.

However, low efficiency and high fuel costs make the marginal cost of emergency backup generators relatively high with a level of around 500 €/MWh[24]. The generators will therefore be at the right end of the merit order curve and only be activated in hours with a strained margin. When they run, they

[23] Reuters 2015a
[24] r2b 2014

will contribute to security of supply and, with their high marginal cost, provide a surplus income for peak thermal plants.

Virtually all services and businesses that face severe consequences in the event of a power interruption have emergency backup generators. One report estimates the aggregated capacity of current emergency backup generators in Germany to be between 4.5 and 8 GW.[25] A conservative estimate is that 2 GW of this capacity will be able to participate in the power market. In relative terms, this is about 3 % of the expected average demand in Germany in 2030. We have used this relative number to estimate the generator capacity for all European countries at 9 GW in our energy-only scenario.

Batteries have a huge potential if investment costs come down

Batteries can store electricity in periods with low prices, and deliver power back to the grid in periods with high prices. As opposed to load shifting, batteries can shift electricity demand over longer periods, technically limited only by their size and charging/discharging rates. However, batteries in the electricity market will usually move demand from peak to off-peak. In that way, they are quite similar to load shifting and their operation therefore has the same consequences on the day-ahead market. Batteries will never set prices above the marginal cost of peak thermal plants, but will contribute to security of supply and smoother variations in residual demand.

Unlike the other flexibilities discussed, battery capacity is not an inherent part of today's power system. How much battery capacity is available in 2030 will largely depend on investment costs and possible income from acting on the energy markets. Other arbitrage opportunities around grid costs and taxes are also important in determining the future capacity. Thus, it is overall profitability, rather than technical aspects, that determine the potential for batteries in a 2030 scenario.

The only marginal cost of using batteries is the loss of energy in a charging cycle. This loss is low. As an example, a system with lithium-ion batteries has a round trip efficiency of around 90 %[26]. With such low marginal costs, batteries can arbitrage on small power price differences. However, just as the usage and profitability of batteries depend on power price volatility, the price volatility will depend on the amount of batteries in the power system. The higher the share of batteries, the lower the observed intraday price volatility. In the end, the investment cost of batteries will limit the power price volatility. If the investment cost for batteries declines, there will be increased investment in batteries and the price volatility declines until the market rebalances around a new equilibrium. Combined investments in batteries and solar cells is becoming popular in Germany. The purpose is to increase self-consumption and save taxes on the power price, as explained more in detail in Box 2.

There is currently rapid development in the battery industry, with cost reductions and performance improvements. Recently, Germany saw the construction of the largest to date commercial grid battery in Europe[27]. It has a power rating of 5 MW and an energy capacity of 5 MWh. The main purpose of the battery is to stabilise the grid frequency. Another common use of batteries in Germany is within solar power storage systems. There are currently more than 10 000 such systems in operation[28].

It is difficult to estimate the amount of batteries available in the power system in 2030 as this depends greatly on both the development of investment costs and power price volatility. Our simulations indicate that battery systems are not profitable with income only from the day-ahead market in 2030 at an estimated investment cost of 200 €/kWh[29]. However, batteries connected to solar power in

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[25] R2b 2014
[26] For example Tesla Power Wall (Tesla 2015), Sonnenbatterie (Sonnenbatterie 2015), Bosch solar battery (Bosch 2015)
[27] Power Magazine 2015
[28] pv magazine 2015
[29] Tesla Power Wall costs a rough 800 €/kWh (including inverter) whereas other conventional battery systems cost around 1500 €/kWh (Wirtschaftswoche 2015). We therefore expect a rapid cost reduction.

households can be profitable as explained in Box 2. Based on these calculations, we assume that 5 % of solar power will have a battery in 2030. This adds up to a capacity of 10 GW power output and a storage capacity of 30 GWh, as we assume that the batteries can discharge in 3 hours[30]. A German study[31] estimates the amount of solar batteries to 3.4 GW – 6 GW in Germany alone in 2030, which is in line with our estimate.

Box 2: Batteries are profitable as they represent savings on electricity bills

A household that has its own solar PV can save money on the electricity bill by optimising its own-consumption of the self-generated power. This is because the household receives a lower price for the electricity it sells to the grid than for the electricity it buys. Income from sold electricity comprises day-ahead or subsidy price, whereas bought electricity includes taxes and grid tariffs. Batteries can help to increase the use of electricity from own solar PV generation by saving electricity from the sunny hours in the middle of the day to the evening peak load hours. The profitability of such solar batteries depends on two aspects:

- Difference between end consumer price and day-ahead price (or subsidy price)
- Cost of battery systems

Solar battery systems were not profitable in the past due to the high investment cost[32]. However, several reports expect such an option to be profitable in the near future or even already today[33]. Our own calculations also indicate that a solar battery system can be profitable if battery investment costs come down. For comparison, the newly launched battery from Tesla has an investment cost of about 800 €/kWh and the power price difference in Germany is today about 20 €cent/kWh.

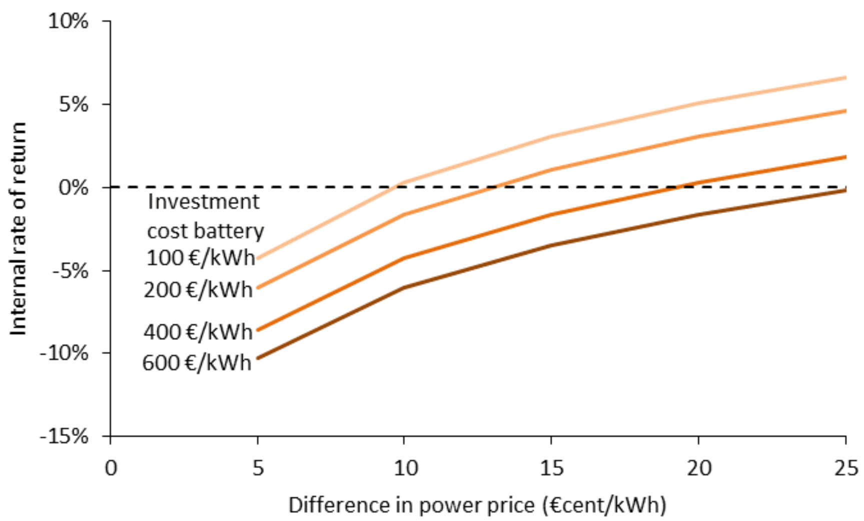

Figure 9. Profitability of batteries connected to a PV-system in Germany as a function of the difference between day-ahead price (or feed in tariff) and end consumer price given different levels of investment cost for batteries. Data from own analysis.

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[30] Solar batteries have a typical discharging time from 1 to 3 hours (Tesla 2015, Sonnenbatterie 2015, Bosch 2015).
[31] Agora Energiewende 2014
[32] Staudacher and Eller 2012
[33] Leipziger Institut für Energie 2014, IW and ewi 2014

4 Capacity margins and power exchange

An energy-only market must operate with a capacity margin that is tight enough to ensure profitability for all market actors. Our simulations confirm this and we observe that the distance to a situation without price formation in the spot market decreases significantly in some hours. Thus, in order to maintain a high level of security of supply, it may be wise to combine an energy-only market with a strategic reserve.

Compared with our reference scenario, we have reduced the total thermal generation capacity by 18 % in order to find a market balance with profitability for all actors. Flexibility technologies replace the most of the thermal generation reduction and help to balance the market, although this includes load shedding potential. Compared with our capacity market scenario, the capacity margin in most European countries decreases 5-15 %. These reductions are probably somewhat exaggerated, due to the conservative assumptions in the reference scenario, but it gives a clear indication of what is needed.

We can see in our simulations that countries share flexible capacity across borders, but to a lesser extent during periods with high residual demand. When the capacity margin is tight in all countries, there is little backup capacity to share and the usage of transmission capacity therefore decreases in these periods.

Thermal generation capacity is reduced

Historically, it has been common practice for countries to build enough generation capacity to be self-sufficient with power at all times. Most of the demand side has been static and not sensitive to price variations. The extensive development of renewable generation capacity, in addition to existing thermal power plants, has led to a capacity surplus in many European countries today. In our reference scenario, sustaining the thermal plant portfolio until 2030 requires considerable capacity payments. A well-functioning energy-only market will instead find an equilibrium between demand and generation capacity, where the margin is tight enough to stimulate demand-side flexibility and generate profitability for the remaining peak power plants. Compared with the reference scenario, we have reduced the total thermal plant capacity by 70 GW / 18 % to ensure profitability for both new and existing thermal plants.

In the energy-only scenario, we have assumed that there are fewer investments in new gas power plants compared with the scenario with capacity mechanisms. In both scenarios, we assume a substantial part of the today's coal and lignite capacity will reach end of lifetime and decommission before 2030. System flexibilities, such as load shedding, load shifting, emergency backup generators and batteries, replace most of the decommissioned thermal capacity. Figure 10 illustrates the difference in generation portfolio between the two scenarios. Renewable energy capacity is equal for the two scenarios.

The amount of thermal capacity in an energy-only scenario is sensitive in relation to many parameters. One important factor is the assumption on distribution and peak value of residual demand. In our simulations, we use the weather period of 1961-2012 to calculate average profitability for thermal plants. This time series includes a number of extremely cold winters, which cause very high residual demand. The last 20 years of weather has not seen winters as cold as those of 1966, 1967 and 1985. Income to thermal power plants in this later period is thus lower and less volatile. If we instead had used the weather period of 1993-2012, installed capacity in the energy-only scenario would have been slightly lower.

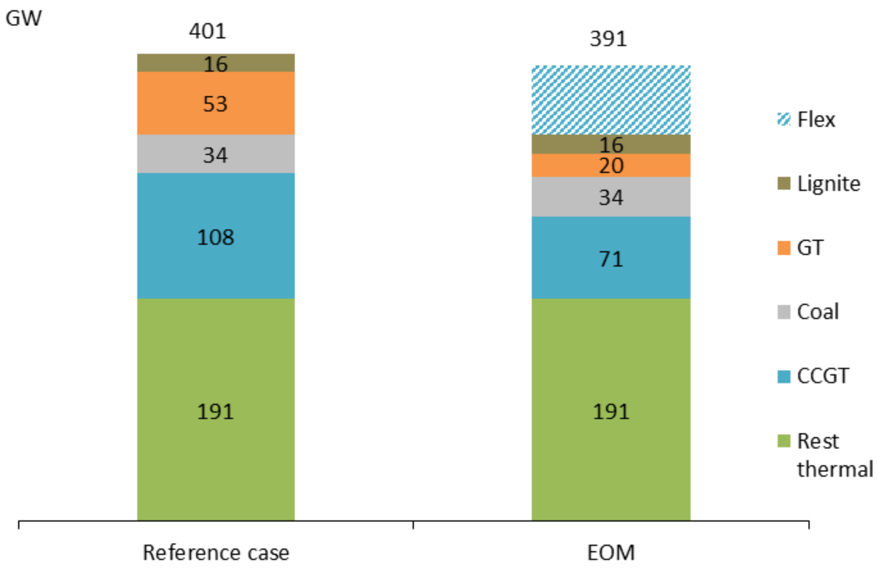

Figure 10. Installed thermal power and flexibility in Europe, comparison between our reference scenario and our scenario with energy-only market (EOM).

Reduced capacity margin and hours with negative margin

The reduction of conventional power plant capacity decreases the capacity margin by 5-15 % in most European countries, compared with our reference scenario. In the most strained hours, the capacity margin is negative due to load shedding. Figure 11 shows an example, where we plot the German capacity margin for both scenarios.

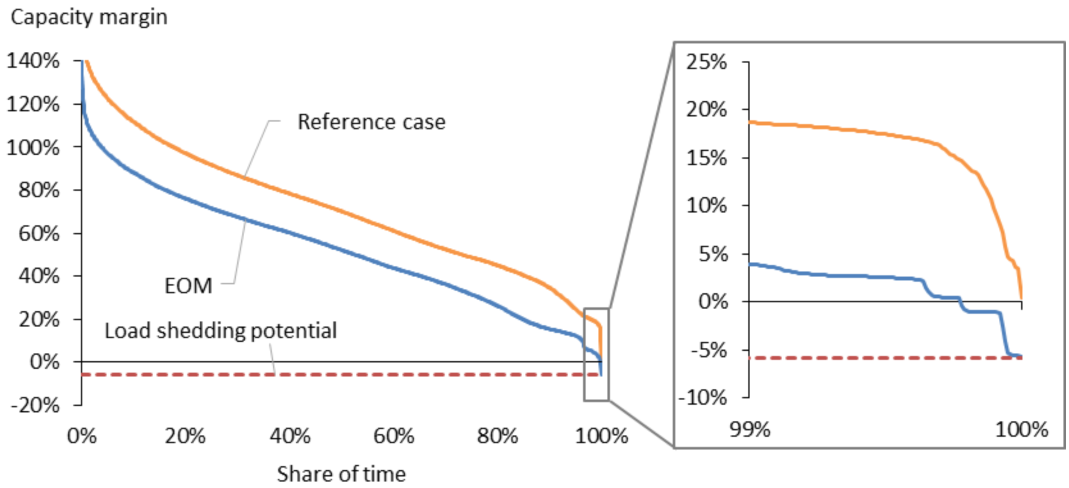

Figure 11. Comparison of the German capacity margin in our reference scenario and our energy-only scenario (EOM).

We have studied a 2030 scenario with an all-European energy-only market over a series of 51 different weather years. Both average and minimum capacity margins vary between the weather years, especially in countries with a high share of renewables and/or temperature-dependent demand. In our analysis, we see Europe having negative margins (which means load shedding sets the price) 0.3 % of the time, on average. However, this varies significantly between weather years. During the years with highest residual load, the capacity margin is negative for roughly 2 % of the time, and the system is close to rationing in two countries for a few hours. In comparison, the scenario with capacity mechanisms has virtually no hours with negative capacity margins.

A market with a tight capacity margin is more sensitive to unforeseen failures or other disturbances. Both loss of generating and transmission capacity may result in higher risk for rationing in one country or larger regions. A failure during the most strained week of our simulations would lead to rationing in several European countries. To ensure a constant secure supply without unplanned disconnections, the energy-only market can be combined with a strategic reserve. This proposal is currently under consideration for the planned energy-only market design in Germany. In order to avoid market interference, the reserve capacity is not allowed to participate in the day-ahead market. It is only activated when supply and demand cannot balance without the use of rationing.

Security of supply will be a regional challenge

We see in our energy-only study that countries quite often have a strained national margin that is offset by imports. European countries will thus depend on each other for capacity contributions. Such dependency is taken into account in a case with capacity markets, as these shall facilitate cross-border participation, but it is obtained without administration in the energy-only case. When investment in generation or flexibility capacity occurs on a free market basis, there is no longer a way to ensure a certain national capacity in the day-ahead market. Compared with a case where each country is self-sufficient, this reduces the overall cost of backup capacity.

Although it helps to share backup capacity in many hours, we also see that the potential is limited during periods with high residual demand. Based on our weather series, we have studied the correlation in European weather. During wintertime, residual demand in one country is more than 60 % dependent on the residual demand in neighbouring countries. This poses no problem in normal conditions; sharing of backup capacity and flexibility generally functions well. The problem lies in days when the residual demand is very high in several countries at the same time. These periods are rare and we see them occur in 15 % of our weather years. During such periods, there is not enough backup capacity to share between countries, and instead we see load shedding.

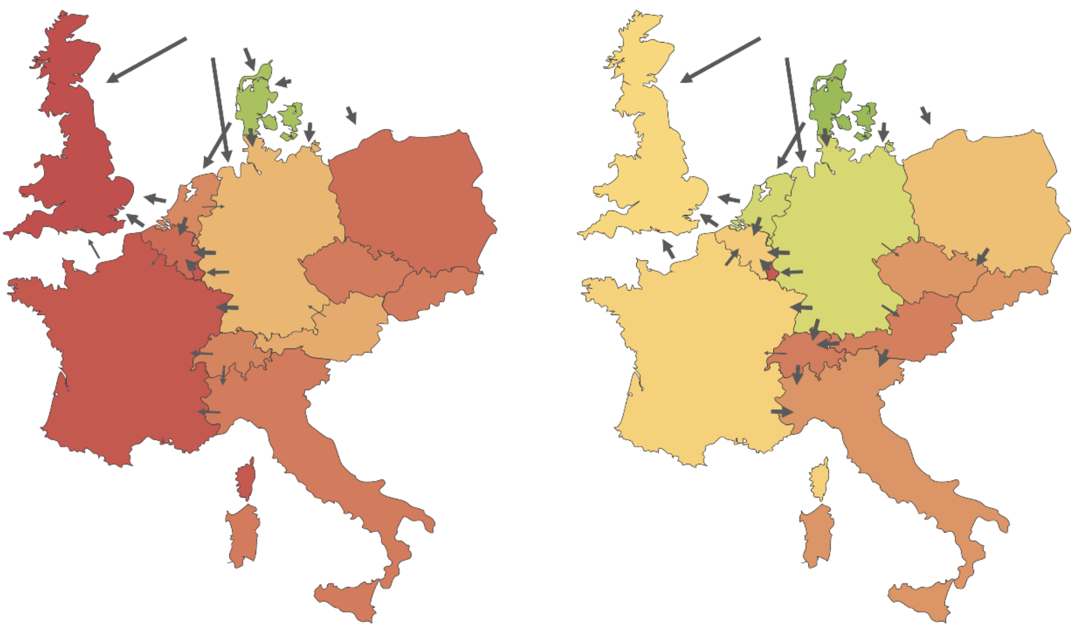

Figure 12. Examples of correlation in residual load between European countries in the power system in 2030. The colour of the countries represents the national capacity margin, where green is positive and red implies voluntary load shedding. To the left, a winter peak hour in a severe situation. To the right, a winter peak hour in a normal situation.

Figure 12 compares two winter situations, one hour in a critical winter and one hour in a normal winter. The colour of the country indicates the severity of the national capacity margin (including imports) and the size of the arrows indicates the amount of power flowing between countries. We see tighter margins and decreased flows between countries in the severe winter situation to the left, as compared to the normal winter situation to the right.

Transmission capacity helps in general but is less used in strained situations

Our simulations do not indicate that an energy-only market requires much more transmission capacity than a market with capacity mechanisms. The sum of all exchanges within Europe increases by a certain percentage in the energy-only scenario, but there is no significant increase of bottlenecks. The exception is between the Nordic countries and continental Europe where the price differences are increasing due to more and higher price peaks on the continental side.

In situations where the residual demand is high all over Europe, which in our simulations occur in 15 % of the simulated weather years, the cross-border exchange is low since no country has extra capacity to share with other countries. The exact changes between the cases in import and export for an individual country in normal situations is dependent on net change in generating capacity in that very area. It is probable that we will see countries with a strong position today (either exporters or importers) move towards a more balanced exchange, due to the market drive towards equilibrium.

An important factor for the utilization of transmission capacity is the introduction of demand-side flexibilities. The flexibilities introduced in our study help balance the intra-day variations in demand and renewable generation. Consequently, power exchange between areas is significantly relieved. Figure 12 shows two examples of this. During an average summer week, we see how German net imports follow the variations in solar PV generation. It is clear that the introduction of low-cost flexibilities in the energy-only case reduces the fluctuations in power flow. We see the same pattern during winter, although less regular. The fact that both summer and winter weeks show weakened net positions for Germany is because we have removed a considerable amount of thermal (over-)capacity in Germany when we created the energy-only case.

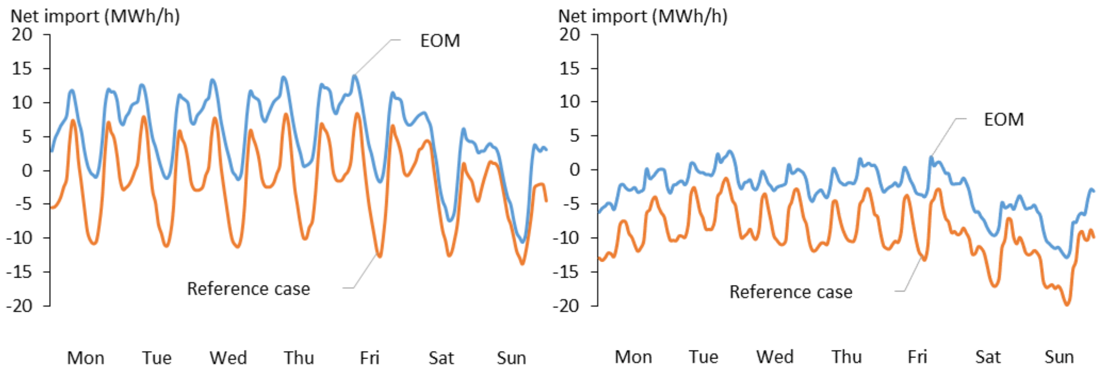

Figure 13. Net German imports compared between the reference scenario and the energy-only scenario (EOM), in average summer week (left) and average winter week (right).

5 Power prices – volatility and price spikes

With the reduction in thermal capacity that we have in our energy-only scenario, power prices become more volatile. This is especially apparent during wintertime in our simulations, when capacity margins are tighter. With a steeper supply curve, small changes in residual demand may shift prices several hundred €/MWh. During summertime, we see less price volatility compared to our reference case. This is due to the introduction of load shifting and batteries, both of which balance the variations in demand and in solar PV generation. Nevertheless, viewed over the whole year, the overall price volatility rises.

The average price levels also increase in our energy-only scenario. The reduction in thermal capacity and the introduction of more expensive bids in the day-ahead market (in the form of backup generators and load shedding potential) boosts power prices in periods. Increased amounts of load shifting reduces peak prices more than it drives up off-peak prices, but has a limited effect on average price levels.

A characteristic of an energy-only market is the need for occasional price spikes. When peak power plants are to recover investment costs from the day-ahead market only, some hours must have a price above the marginal cost for these plants. This is the case when load shedding sets the price. We see in our energy-only scenario that prices during short periods can reach levels up to several thousand €/MWh. The number of such price spikes increases considerably, compared to our reference scenario.

Power prices become more volatile in situations with high residual demand

If an energy-only market has a tighter capacity margin than a market with capacity mechanisms (which is the case in our two cases), the energy-only market should generate more volatile power prices. The magnitude of the volatility increase mainly depends on three factors:

- Reduction in conventional thermal power production capacity
- Cost of load shedding
- Potential for load shifting and batteries

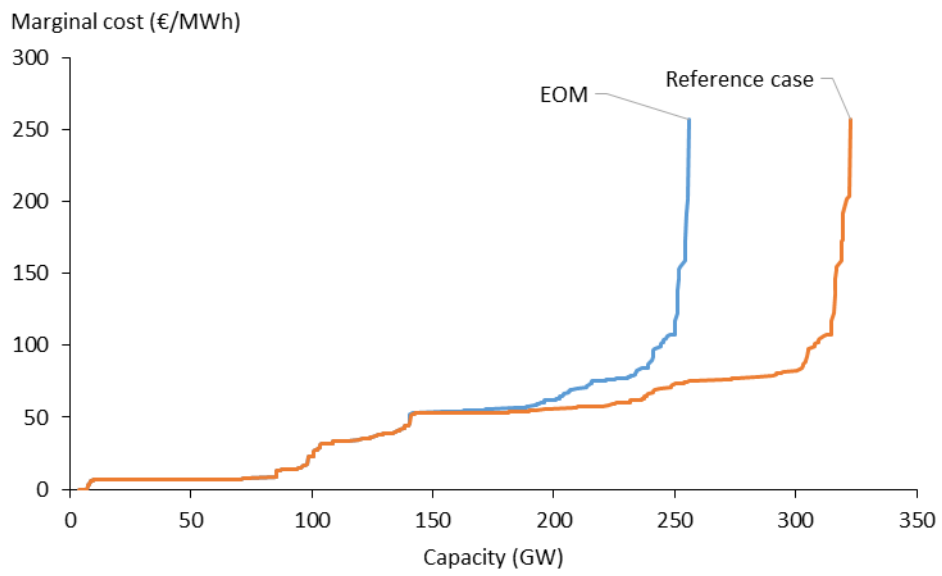

Figure 14. Supply curves for European thermal power plants, comparing the reference scenario and the energy-only scenario (EOM).

The reduction of thermal generating capacity in our energy-only scenario leads to a steeper supply curve, as shown in Figure 14. During high load hours, a change in residual demand will therefore lead to a greater change in price in this scenario than in the scenario with capacity mechanisms. In short, the market becomes more volatile. In periods when load shedding sets the price, this sensitivity to changes in residual demand is even greater, as the difference in price between one hour with load shedding and one hour without is of considerable magnitude.

The introduction of load shifting and batteries decrease price volatility on a general basis. Their biggest impact on price volatility is during spring and summer, when they significantly help to balance the variations in solar PV generation. Load shifting sets the price in periods with low demand, as the flexible consumers increase their demand in these periods. Conversely, the load shifting will reduce the price in periods with high electricity prices. This is clear for the average July day in Figure 15 where there is considerably less price volatility in the energy-only scenario. Even though load shifting and batteries decrease volatility considerably during such times, they provide little extra help in times of high residual demand. During winter, the effect of load shifting and batteries on price volatility is much smaller than during summer. The average February day in Figure 15 illustrates this. Here, price volatility increases due to more strained periods with high residual demand.

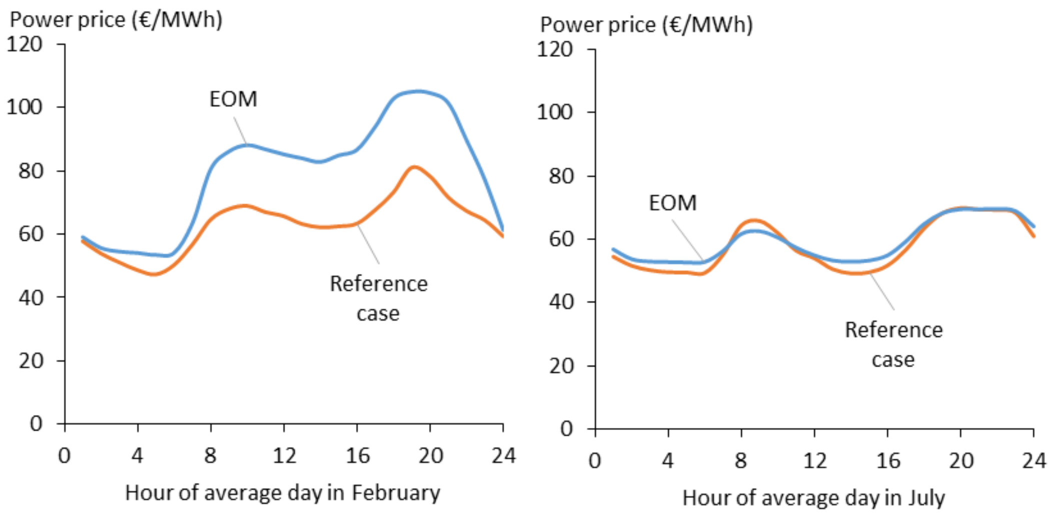

Figure 15. Average intraday price volatility in Great Britain in February (left) and July (right).

In sum, we see increased price volatility in hours of high residual demand, and decreased volatility in times of renewable generation surplus. Trying to estimate the overall effect on volatility, we define intraday price volatility as the average of hourly deviation per day from the average price level of that same day. If we look at this average over a year, we see that intraday price volatility doubles in our energy-only scenario, compared to our reference scenario. The periods of increased volatility increase the average more than the periods of decreased volatility do.

Results from our sensitivity analyses around the energy-only scenario show that a doubling of the battery capacity only leads to a reduction of average price volatility by roughly 10 %. This reduction occurs mainly due to changes in power prices in winter. Higher battery capacity helps in strained winter periods and leads to a reduction of the peak prices, and thus also volatility. We see almost no changes in the power prices in summer when battery capacity is increased.

Average price level will increase

Average price levels increase in our energy-only scenario. The three main factors that affect price volatility also influence price levels. We have already discussed the fact that the decreased thermal capacity in our energy-only market scenario leads to increased prices in high load hours. The tighter margin causes peak power plants to run more often. The thermal capacity reduction is in itself the main driver for increased power prices. What type of capacity that is decommissioned from today, or that is not commissioned at all when there is no capacity market, determines the size of the price increase and during which periods the increase will take place.

High-cost load shedding determines the extreme peak power prices. Although this cost is uncertain and, in part, difficult to estimate, it is likely higher than the most expensive thermal power plant. Even a few hours of activated load shedding can therefore substantially affect the average price level in a short period. In very cold and windless years, load shedding may even affect the average annual price. The effect is naturally highly dependent on the cost magnitude for voluntary disconnection of different demand groups or single industries.

Introduction of batteries and load shifting leads to lower average power prices. The shifting of load reduces peak prices more in absolute terms than it increases off-peak prices. However, the effect is quite small and we have seen in our sensitivity analyses that even large numbers of batteries in the European system only lead to a slight decrease of the average power price (up to 1 €/MWh). Load shifting and batteries affect power price levels significantly less than load shedding and thermal capacity reduction.

The overall effects on price are visible in the price duration curve for France, in Figure 16. We see that prices increase most in the high range, a little less in the low range and are quite unaffected in the mid-range. This is a result of the fact that peak prices in wintertime increase considerably and that load shifting and batteries prevent prices from sinking too low in the summer.

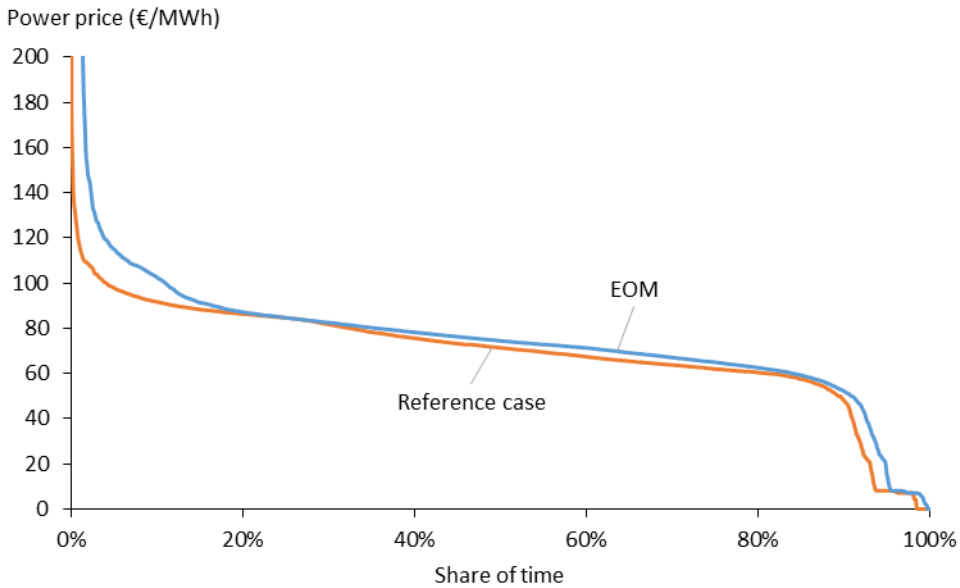

Figure 16. Price duration curve for France.

The results are sensitive to several uncertain input parameters. However, our analysis indicates that average power prices in the energy-only scenario rise regardless of the underlying cost assumptions and potential for load management. Average price levels increase in a 10 €/MWh order of magnitude compared to our reference scenario. This increase is dependent on the size of the minimum capacity margin. If the obtained market equilibrium would have an even tighter margin, the increase in average price level would rise further. All the same, the increase in the power prices is quite robust and a significant reduction in load shedding costs, as well as lower fuel prices, have only a marginal impact on the increase.

Extreme price spikes are possible

With the reduction in thermal capacity, and demand actively shedding load at a high bid price, extreme price spikes will occur in the energy-only market. This is not a sign of market failure, it is rather an indication that the market is functioning. These price spikes both generate a surplus income for peak generating plants and stimulate demand-side flexibility. Nevertheless, price spikes incur high temporary costs for consumers, and may be controversial as they are much higher than what prices have been traditionally.

Our simulations show that power prices can reach levels of several 1000 €/MWh in periods with very high residual demand and load shedding. These power prices represent the value of the electricity for the industrial companies that apply load shedding in our simulations. Such prices are at a level more than tenfold that of current peak power prices. The emergency backup generators are the most expensive thermal power in our analysis, at a marginal cost of 500 €/MWh. We can see in Figure 17 that load shedding on average sets the price for very few hours. Looking at an average over 51 weather years, European prices over 500 €/MWh will only occur in around 20 hours per year.

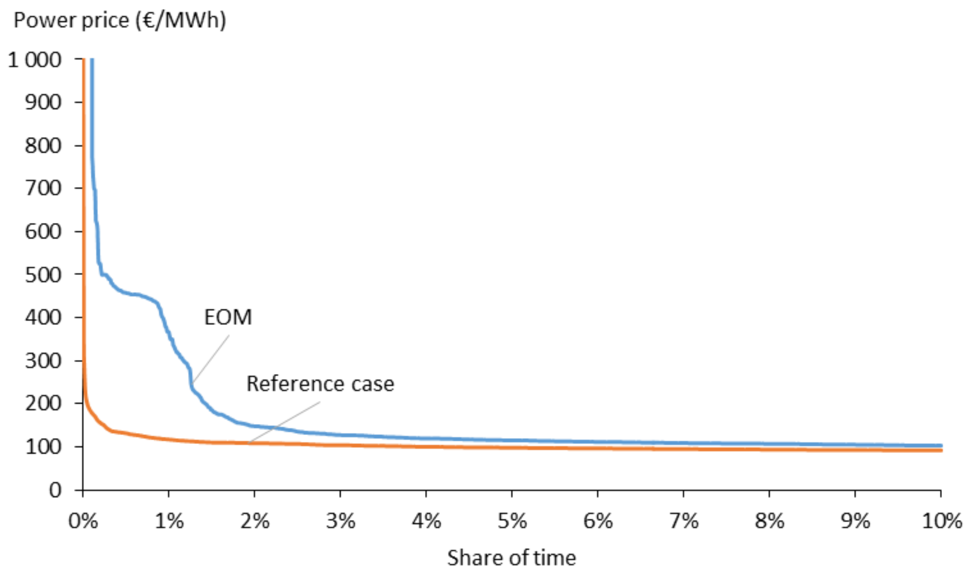

Figure 17. High end of price duration curve for France.

It is important to highlight that price spikes are very dependent on rare weather events. During more than half of the simulated weather years, 1962-2012, there are no hours with prices above the marginal cost of emergency generators. In Figure 18, we can see that five extreme years bring up the average. Four of these five weather years occur in the cold and dry 1960's, and one in 1985. During these five cold winters, load shedding can be price setting in 4-5 days in a row.

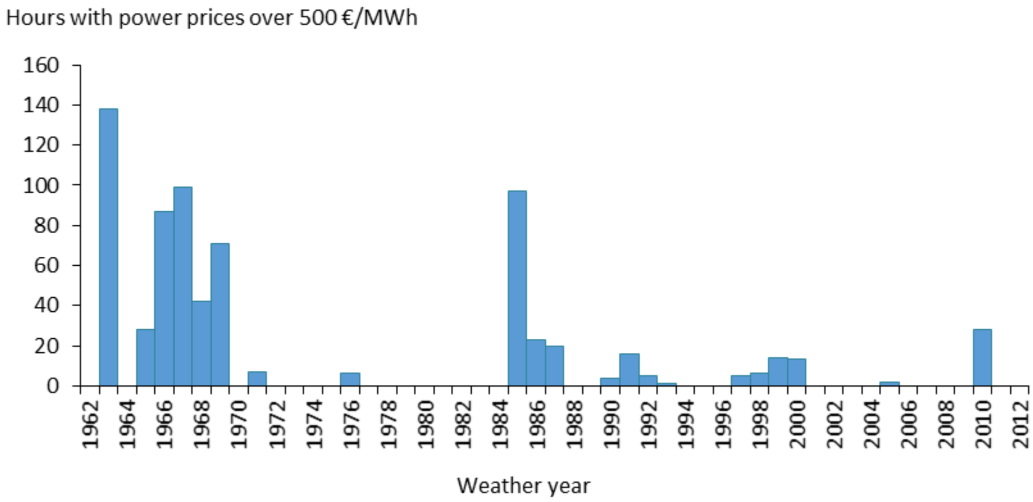

Figure 18. Number of hours with very high French power prices for the weather years 1962-2012.

The low frequency of price spikes complicates the dimensioning of the power system. It is not clear whether anyone is willing to invest in peak plants and flexibility technologies that run so infrequently. Even if such capacity contributes in one out of ten years, those years may occur at longer intervals. The number of peak power plants in our energy-only scenario would have been lower, if we had designed it by using only the last 20 years of weather history. Consequently, the use of load shedding would increase in these years to balance the lower capacity of peak power plants.

The Nordic and German power exchanges, NordPool and EPEX day-ahead, have a maximum power price of 3000 €/MWh today. This is a theoretical price ceiling set by the auction rules. The real absolute maximum power price is hard to determine since it depends on the value of electricity for the customers that can accept load shedding. It is likely that the exchanges will expand the auction price ceiling if it would appear to constrict the functioning of the market.

6 Contribution from system flexibilities

Marginal cost and usage characteristics of system flexibilities vary between the technologies. They thereby contribute to the power system in different situations. While our simulations show low-cost flexibilities in daily use, high-cost flexibilities will only contribute in periods of strained capacity margins (which generate sufficient short-term price differences). As a result, flexibilities with lower marginal costs will have a more evenly distributed income and therefore also more secure and predictable profitability than high-cost alternatives. Load shifting and load shedding, both with low investment costs, are profitable based solely on day-ahead market income in our energy-only scenario, whereas we assume batteries have alternative income streams.

It is clear from our analysis that voluntary load shedding is the key to finding a balanced energy-only scenario. Hours with load shedding at high prices ensure peak thermal plants receive the income surplus they need in order to be profitable. The existence of load shifting, batteries and emergency generators helps to balance the variations in residual demand, but they are not strictly necessary in finding an energy-only market equilibrium. Sensitivity analyses show that it is possible to find an equilibrium without these flexibilities as long as there is enough load shedding potential. Such a scenario demands more thermal power plants, but not necessarily more hours with load shedding.

Load shifting helps balance residual demand

Inexpensive flexibility options include batteries and low-cost load shifting. These technologies have low marginal costs for shifting demand from peak periods to off-peak periods. We see both technologies in use daily to arbitrage on daily price differences in our simulations. This usage pattern results in a daily peak shaving. In general, both morning and afternoon peaks are shaved, and especially the midday off-peak is offset. The other investigated system flexibilities do not cause this regular pattern.

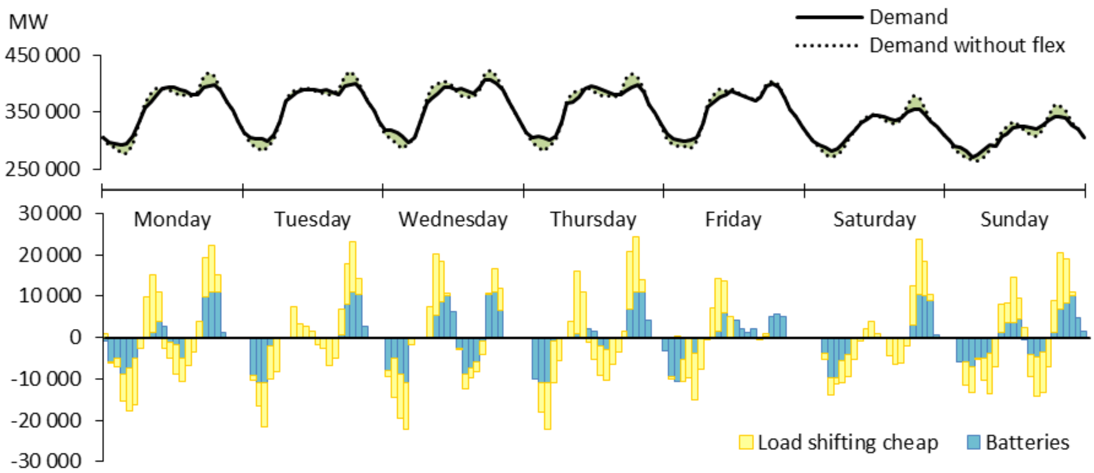

Figure 19. Contribution and effects of low-cost load shifting and batteries for Europe during a typical winter week in the energy-only scenario.

Low-cost load shifting is included in the analysis at close to zero cost, reflecting that many electric appliances could possibly support load shifting at no direct cost other than a small investment cost in automatic control linked to market power prices. Figure 19 illustrates a usage pattern for these flexibilities in a typical winter week.

Low-cost load shifting and batteries have very similar characteristics and compete for the same market shares. Thus, the amount of batteries in the power system will depend on the potential and profitability of low-cost load shifting.

It is reasonable to expect that there will be load shifting at a range of marginal costs available to the market. If there is sufficient price volatility during a day, load shifting with a higher marginal cost will also be able to arbitrage, for example flexibility inherent in industrial processes. As with cheaper options, high-cost load shifting is limited in time, meaning it cannot shift load longer than a few hours. As opposed to low-cost load shifting, these processes are more infrequently deployed and do not compete directly with batteries for profitability.

Both cheap and expensive load shifting require a technology that facilitates load shifting, including automatic systems or possibly aggregator services. The cost of shifting demand will decrease with improved support technologies, making it easier for customers to respond to price signals.

Load shedding and emergency generators contribute over longer periods

Load shedding is a flexibility option with high marginal cost, because the household or industry that reduces its demand will lose comfort or income. This system flexibility only activates during times of extremely high residual demand, when the system is close to rationing. Different user groups will have different costs related to cutting demand.

An advantage of load shedding is that the reduction in power demand of many industrial processes may last over longer periods. As shown in Figure 20, the simulations show load shedding contributing over several consecutive days in an especially strained week with continuous critical residual demand levels. It is unlikely that all industry players have the option to stop production during the day and start up production again at night, as the simulation results suggest. Rather, economies of scale could make it more profitable to shed load over an entire period if the outlook for the following days would be as shown in Figure 20.

Emergency generators have a lower marginal cost than load shedding, but high enough to only activate in situations with very high residual demand. Emergency generators also have the capability to run over several days in a row. Figure 20 shows that emergency generators run continuously over the strained hours, whereas load shedding reduces at night. The running of emergency generators over longer periods requires sufficient fuel storage on site and/or regular refilling of fuel tanks. Lack of infrastructure for refuelling could, in reality, limit the duration of the capacity contribution from emergency backup generators.

Flexibilities complement each other – thermal plants still play central role

An interesting observation in our analysis is the interaction between the flexibilities in periods where the system is close to rationing. In our example strained week, shown in Figure 20, emergency backup generators and load shedding run at night to allow batteries and load shifting to recover and contribute again with capacity during the tightest hours the following day. It is important to remember that the power system still relies heavily on thermal power plants in such situations. In the worst hours, thermal power production covers more than 70 % of the demand and all available power plants run at full utilization during the critical period.

The illustration portrays one of the extreme winter weeks in our analysis, and the probability that such a week will occur is quite low. Nevertheless, it serves as an example of what kind of situations the electricity market will have to manage. It may be that in reality, the behaviour of consumers would be different in the depicted situation. If the price outlook for a given week is like the example, even households might reduce their demand. Industry players could possibly choose to shed all load during this period to save overhead costs, rather than follow a strategy to halt production during the day and start up again at night. This would reduce the total power demand over a longer period and could eliminate longer periods of very high power prices and the observed complementing pattern in use of flexibilities.

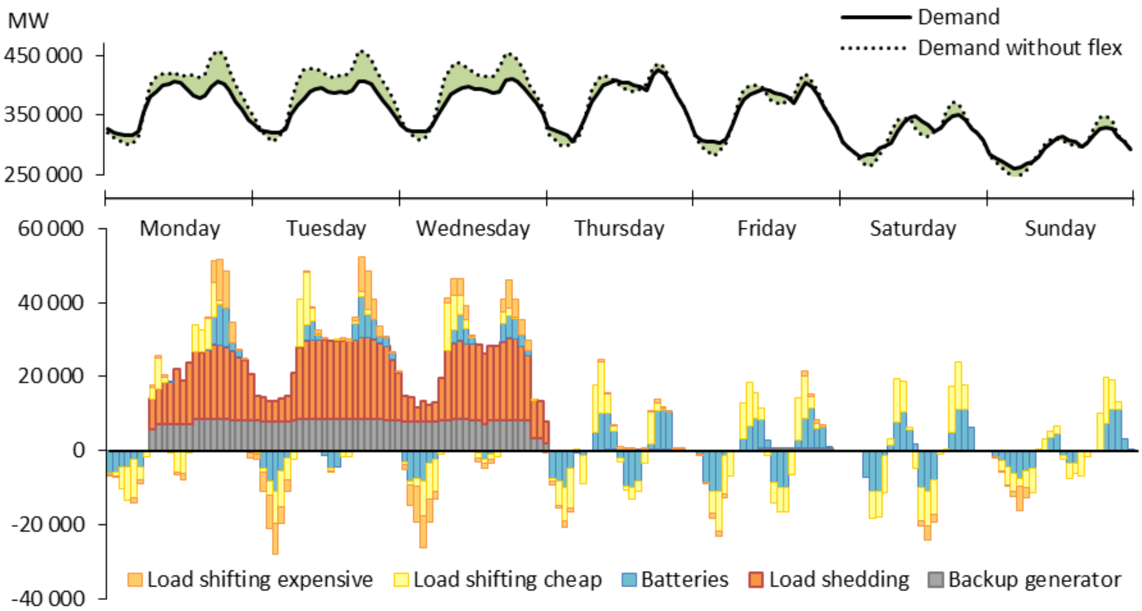

Figure 20. Use of system flexibilities in Europe in a critical winter week in the energy-only scenario.

Most flexibility options are profitable in our scenario

The system flexibilities that have low investment costs are profitable in our energy-only market scenario. This includes load shifting and shedding, but not batteries. Load shifting and shedding generating sufficient income from the day-ahead market has been one of the design criteria. A common factor for load shedding and load shifting capacity is that the expected cost for making it available to the market is relatively low. They therefore have a cost advantage over thermal peak power. Nevertheless, we see that profitability robustness varies between the different types of flexibility.

Batteries have higher investment costs than the other flexibilities and cannot generate enough revenue in our energy-only scenario to reach expected rate of return. There are still many incentives to invest in batteries, where one example is the possible cost savings discussed in Box 2. We therefore assume that there will still be a certain amount of battery capacity in our energy-only scenario and that the bulk of their income comes from the day-ahead market.

In general, the profitability of often-used flexibility is less sensitive to changes in power prices than rarely used flexibility. Low-cost load shifting and batteries are in daily use and therefore secure a small, but frequent, income. This is more robust than securing a large income or avoiding a large expense on a few occasions, such as emergency backup generators, high-cost load shifting and load shedding do. For these three technologies, income is closely linked to the probability of critical situations occurring in the power system. Seen over all the weather years in our analysis, high-cost flexibilities are more profitable than low-cost, but if we exclude a few of the most extreme weather years, their internal rate of return drops rapidly. Because we assume that emergency backup generators have no need to recover their investment costs, they cannot become completely unprofitable. High-cost load shifting and load shedding, on the other hand, may have negative internal rates of return, even with low expected investment costs, if there are no years with more extreme weather periods and very high residual demand.

Profitable operation of flexibilities need not be restricted to an energy-only scenario. Our analysis shows that cheap load shifting can be profitable also in the day-ahead market with capacity mechanisms, which has considerably less price volatility. Other forms of system flexibilities could possibly also bid directly into a capacity market and ensure profitability outside the day-ahead market.

7 Profitability of power plants

In an energy-only market, the profitability of power plants is more dependent on power prices and more volatile than in a capacity market. Introducing the energy-only market forces the industry actors to adapt to the desired future situation of fewer thermal generation units more quickly than in a capacity market. The absence of capacity mechanisms will quickly lead to a decommissioning of many unprofitable power plants, and consequently the remaining generation portfolio will have profitable operation.

The results from the simulation for 2030 show highly variable profitability for power plants, depending on the generation technology. The results are, in many ways, comparable to the profitability results for flexibilities. Base load production, with low marginal costs, has an even income distribution over time, and relatively low investment risk. Peak load production, with high marginal costs, is more dependent on the occurrence of periods with high residual demand to make a profit. The investments in peak load plants are thus more risky, and investors face the possibility of consecutive years without income.

The increased average prices in the energy-only scenario will lead to better profitability in renewable generation, but the majority of renewable projects will still depend on subsidies. Solar PV is the renewable generation technology that profits the most from the introduction of flexibility technologies, due to the introduction of load shifting and batteries that absorb the fluctuations from high midday solar production.

Income distribution is different for base load and peak load generation units

All thermal power is profitable in our scenario for a future energy-only market, because this was one of the design criteria. In contrast, only investment in lignite plants has an internal rate of return above 10 % in our reference scenario with capacity mechanisms, while investments in CCGT and OCGT all are near or below zero profitability.

Even though all plants in the energy-only scenario are profitable, the robustness of the generated income is highly variable. Similar to the case of flexibilities, base load power plants with lower marginal cost have more robust income than peak load plants with high marginal cost. In contrast to the flexibilities, power plants have a larger variation in investment costs, where base load power normally is more expensive to build than peak power. This evens out the differences in income, and leads to less variation in the internal rates of return between different types of power plants.

Because of the fuel price assumptions in our scenarios, coal comes before gas in the merit order curve. Gas power profitability is therefore much more sensitive to changes in residual demand than the profitability of lignite, nuclear or coal. As shown in Figure 21, OCGTs and CCGTs have a highly volatile yearly profitability over the different weather year series. In comparison, coal and lignite power plants have a more stable income stream. Independent of fuel cost assumptions, the technologies with highest marginal operation costs will have the least stable profitability.

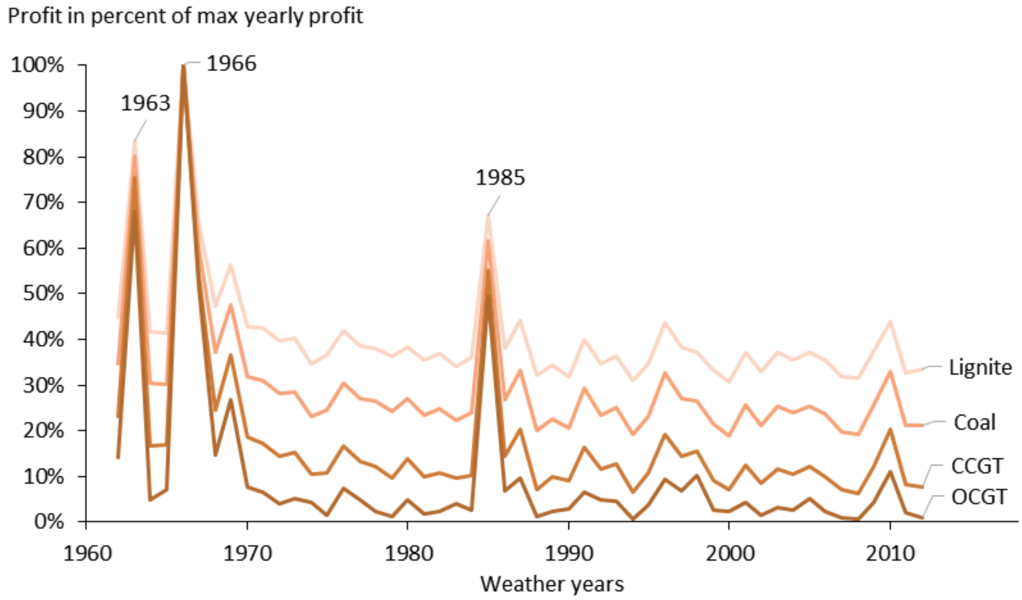

Figure 21. Volatility of yearly profitability of different power plants in our energy-only scenario. Measured relative to the maximum profit in a year over our simulated 51 weather years.

Power price formation in the hours with the tightest capacity margin is very sensitive to changes in residual demand. If energy efficiency measures or lower-cost load shedding brings down the residual demand only a few percentage points in such an hour, peak power plants can quickly turn from profitable to unprofitable. Naturally, base load power also suffers from reduced demand, but because of their higher load factors, the effect of such abated price spikes is more limited.

Investments in peak power capacity are high-risk

Peak power capacity depends on price spikes during times of very high residual demand to recover its investment cost. An investor will therefore have to rely on the continued occurrence of extreme weather events to generate sufficient revenue. An extreme weather event, seen from the electricity market perspective, is a period with low temperatures, low wind speeds and low solar radiation, leading to high residual demand. It is clear in Figure 22, that in our series of 51 historical weather years, there are three years that generate the bulk of income for a given European gas power plant. For the last 25 years, no such extreme weather years have occurred. It is difficult to say whether this is due to climate change or normal variations. This illustrates the considerable risk that a peak power investor takes in such a market. Investors could cover their risk with financial products, such as insurance or long-term contracts. Such measures remove or mitigate the downside risk of consecutive years with little income, but will also remove the upside possibility of very profitable years. It is also uncertain to what extent such financial contracts will be available.

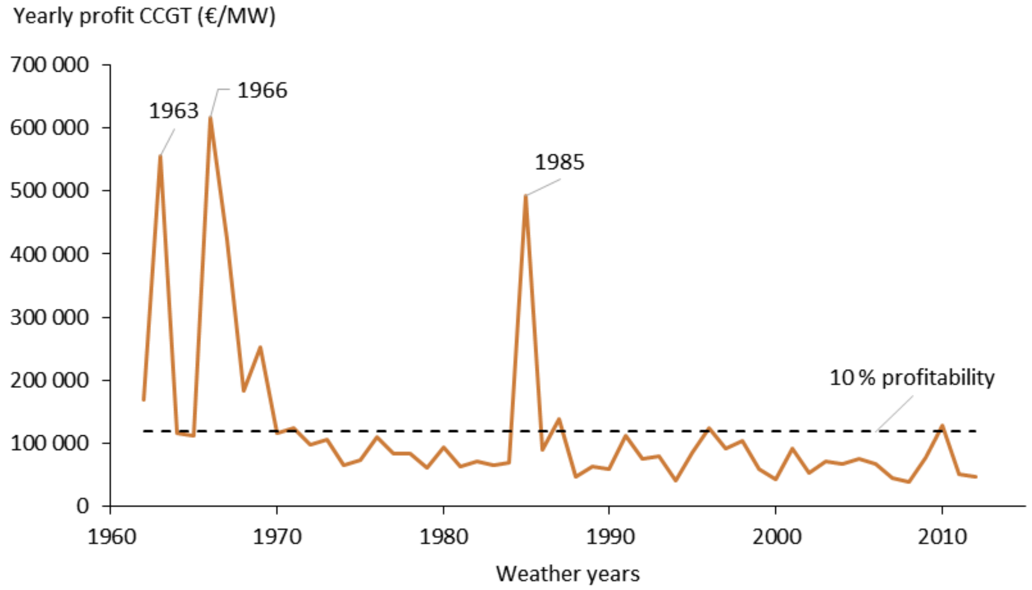

Figure 22. Example of yearly profit of a German CCGT power plant in the energy-only scenario. Most years do not generate enough income to yield a 10 % internal rate of return on investment.

Assuming a scenario where investors choose to calculate with the last 20 years of weather, the thermal generation portfolios would look different and have fewer units. Still, this does not alter the conclusion that peak power plants will be highly dependent on income from less frequent weather years. This investment strategy would simply lead to a different equilibrium point, where the fewer peak power plants still would depend on periods of very high residual demand. When we performed a sensitivity analysis and designed an alternative energy-only scenario, according to the last 25 years of weather series, we saw in our simulations that a reoccurring weather year such as 1966 or 1985 would pose a significant threat to European security of supply.

The low frequency of high peak power prices is not the only risk for an investor in peak power plants. Price spikes will most likely be controversial, and both authorities and consumers will have to accept the occurrence of high prices at times in an energy-only scenario. If European countries choose to opt for energy-only markets, they would have to opt for this with full dedication and not start to meddle with the markets when price spikes occur. Otherwise, this would add uncertainty to the investment decision, as the investor has to rely on stable conditions over the investment.

Introduction of system flexibilities also add uncertainty to investments in power plants. Load shifting and batteries help balance the residual load, and therefore reduce the running hours for conventional capacity. Long-term investment in peak power plants will depend on the outlook for implementing these flexibilities in the power system. However, our sensitivity analyses show that an increased amount of batteries and load shifting will rather reduce the profitability of the already existing flexible capacity, than that for new peak power capacity. This means, according to our cost assumptions, that load shifting and batteries will become unprofitable before peak power plants do. The profitability of peak power plants is therefore less sensitive in relation to increased amounts of batteries and load shifting than perhaps would be anticipated.

Regardless of market design, there are many more uncertainties surrounding power plant investments, such as technology costs, climate policy, fuel price expectations, etc. However, these have not been specifically considered in this analysis, as they are similar between our energy-only scenario and our scenario with capacity mechanisms.

Continued need for renewable power subsidies, but at a decreased cost

Renewable power generation also benefits from the higher average power prices in an energy-only market. We assume that renewable generation capacity bids directly into the market and does not merely rely on feed-in tariffs. We see in our energy-only scenario that the internal rate of return on investments in solar PV doubles, compared to our reference scenario. This is primarily due to the increased amount of batteries and low-cost load shifting that absorb the daily fluctuation in solar PV generation. The internal rate of return increases somewhat also for onshore and offshore wind, although relatively less than for solar PV.

Onshore wind starts to reach acceptable rates of return without subsidies in our energy-only scenario. Offshore wind power still needs subsidies to achieve an expected rate of return in investments. Nevertheless, we see that an energy-only market may decrease the total cost of renewable subsidies, as more income is recovered from the day-ahead market.

8 Germany as a lone energy-only market

Today, European countries are discussing different solutions to the challenge of secure supply. Both capacity schemes and energy-only markets are under discussion and countries are currently deciding on diverse market designs. As Germany, to some extent, goes against the grain, we have decided to investigate an alternative scenario where, in 2030, Germany is the lone energy-only market among capacity markets.

The consequences of such a development are uncertain, but our simulations indicate that such a scenario may suffer from imbalances. Germany will most likely have a reduced amount of thermal capacity in the day-ahead market, as compared to our case with an all-European energy-only market. If neighbouring capacity markets bring considerable surplus margins, the probability of price spikes will plummet, with the consequence that Germany will lack investment signals for peak power plants. Without such investment, Germany will have to rely heavily on imports in strained hours. This may pose a challenge for national security of supply.

Even though future market development may be uncertain, it is probable that European market design will harmonise. If not in theory, at least in practice. The difference between our simulated scenarios would diminish if capacity markets were designed to facilitate demand-side participation and with less excessive capacity surplus.

Different directions in today's European market design

European countries are discussing different solutions to the investment challenge for secure supply. Great Britain[34] and France[35] have both introduced capacity markets, but with relatively different designs. Germany on the other hand has proposed to keep an energy-only market, but combine it with a strategic reserve[36]. The European Commission has seen national capacity markets as a threat against the target of a single European market. DG Competition has therefore launched a sector-wide investigation into capacity schemes[37].

It is possible that we will see diverse European market designs for the coming 5-10 years. We have therefore completed a sensitivity study where Germany is the lone energy-only market among neighbouring capacity markets. The intention of this analysis is not to be a forecast of what will happen, but to illustrate possible consequences and challenges of such a scenario.

Decreased thermal capacity and increased dependence on import capacity

Because of the ongoing market design process in Germany, we have constructed an alternative scenario to the all-European energy-only scenario, where Germany is the only continental European country with an energy-only market. For the other continental European countries, we have assumed capacity markets and ample capacity margins (i.e. the same modelling as in our reference scenario). In order to obtain a market equilibrium with profitable market actors in this alternative scenario, we need to reduce German thermal capacities more than in the scenario with an all-European energy-only market. With a larger supply of thermal capacity in neighbouring countries, Germany will often be able to import power in strained hours and there will be fewer hours with price spikes. German peak plants thereby present a weaker investment case and less investments are made. In short, the regional available generation capacity has to be around the same level in both scenarios in order to make German thermal power plants profitable. If the aggregated European capacity margin is higher, German margins must be lower.

[34] Department of Energy & Climate Change 2015
[35] Reuters 2015b
[36] Bundesministerium für Wirtschaft und Energie 2015
[37] European Commission, Commission Decision of 29.4.2015

Figure 23 illustrates the expected thermal generation capacities, available for the day-ahead market, in our three scenarios. Based on our simulations, we expect that Germany will have to reduce the installed capacity in thermal power plants by another 10 GW compared to the all-European energy-only scenario. This number is uncertain and depends heavily on the level of capacity surplus in the neighbouring countries. A less spacious capacity margin in the neighbouring countries would reduce the decrease between the scenarios.

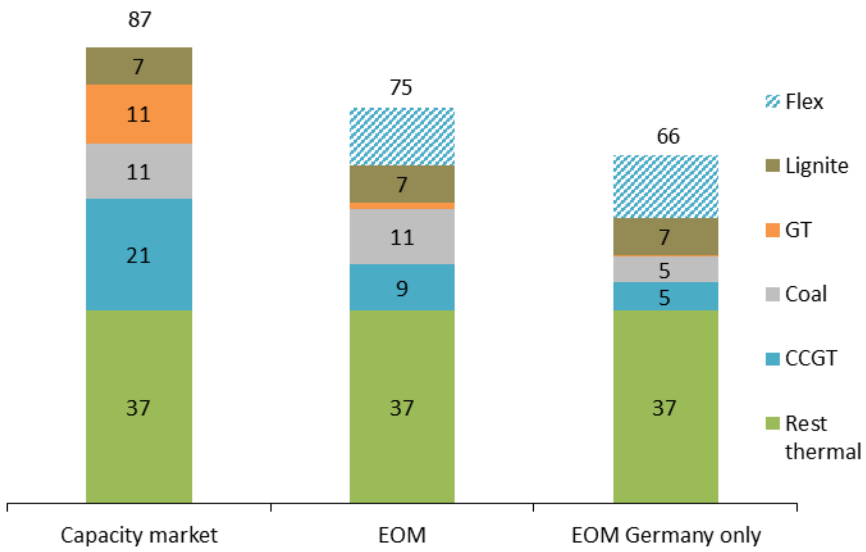

Figure 23. Installed thermal power in Germany is lowest in our case where the country is a lone energy-only market.

With decreased national generation capacity, we see Germany becoming more dependent on imports in our alternative scenario (with Germany as the lone energy-only market). Figure 24 shows how the German net position turns from exporter in our reference scenario, to importer in our energy-only scenarios. When Germany is the lone energy-only market, it relies heavily on imports in periods of high national residual load. In such situations, the country utilizes up to 100 % of its import transmission capacity, while having no extra generation capacity available in the market[38]. We have not modelled unexpected outages in generation or interconnector capacities in our study. It is nevertheless evident that a failure in a central plant or power line during strained periods could quickly lead to situations with poor security of supply in Germany. To mitigate this risk for rationing, it seems necessary to combine the energy-only market with a strategic reserve.

[38] The strategic reserve compensates but is kept outside of the day-ahead market

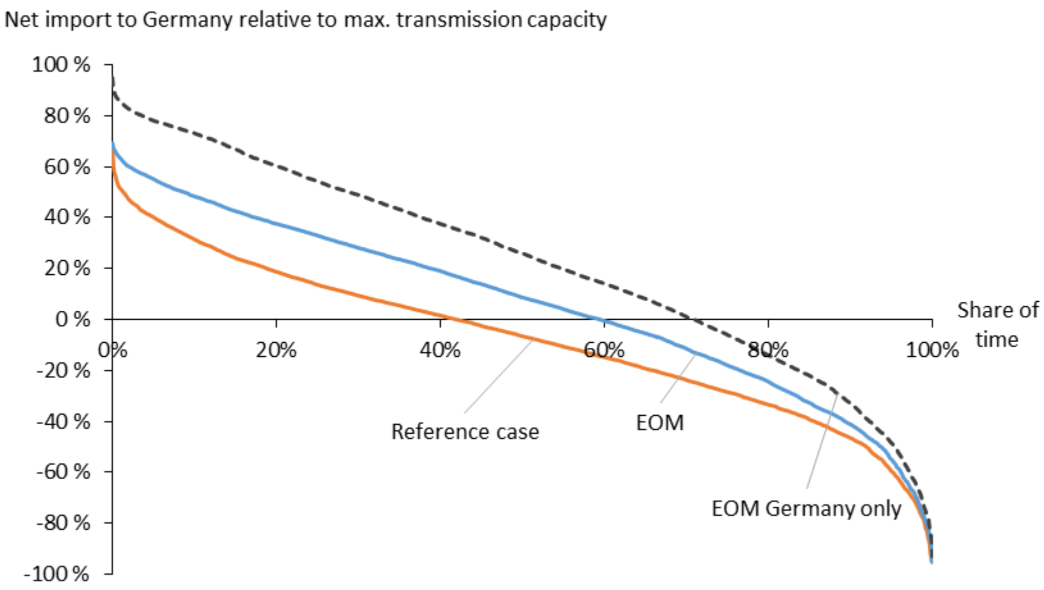

Figure 24. Net import to Germany in a weather year with high residual demand (1985).

Countries likely to harmonise their market design in the long term

The long-term consequences of a German energy-only market among neighbouring capacity markets are difficult to predict. We have seen in our simulations that such a scenario can present challenges to the market balance, even if Germany combines the energy-only market with a strategic reserve. If Germany were to depend on import capacity in critical hours, it is possible that they would gradually need to increase the size of the strategic reserve. In return, neighbouring countries could see a need to increase the ambitions of their national capacity markets in order to compensate for the lack of investment in flexible capacity in Germany. Europe could risk entering an unbalanced scenario where market forces counteract each other.

However, we believe that a harmonised development is more likely. There is still a possibility that Germany will turn around and introduce a capacity market, even though they state a final decision in the official documents[39]. It is also possible that all of Europe will move towards an energy-only market, even if this poses its own challenges as we have discussed in this report. Should the difference in market design between European countries persist, it is still likely that the application of the markets will be similar. It is probable that capacity markets will include demand-side flexibility and possible that the demanded capacity margin could be lower as compared to our simulated case. This would reduce the practical difference between the two market designs and enable them to interact constructively.

[39] Bundesministerium für Wirtschaft und Energie 2015

9 Consequences for the Nordic system

There is a close relationship between the Nordic and the European electricity markets. In particular, the German power price has a major impact on Nordic price formation. The relationship between the markets will become tighter over the coming 5-10 years. The integration is both physical, through increased interconnection capacity, and regulatory, through implementation of joint EU legislation. Implementation of a European energy-only market therefore has consequences for the Nordic market. Essentially, we expect an increase in the number of hours when Nordic countries import continental peak power prices. With more extreme European price spikes, the Nordic price level during these hours will at times become very high. This increased willingness to pay for Nordic flexibility can eventually stimulate increased demand-side flexibility and/or investments in extension of regulated hydropower capacity.

Import of continental peak prices occurs today

The Nordic countries have a large amount of reliable generation capacity in hydropower and nuclear. Even so, there are hours when there is not enough generation capacity available to cover both regional demand and full export on all interconnectors out of the region. To reduce the export in these hours, the Nordic power price must increase to the price level of its neighbours. The export will first decrease to the area with lowest price difference to the Nordics, and last to the area with the highest. In this way, the Nordic market occasionally directly imports the peak power price from neighbouring areas. Today this happens in 1-2 % of the hours in a year, but it depends on the weather situation. It is more common during dry and cold winters, but also occurs in a normal winter.

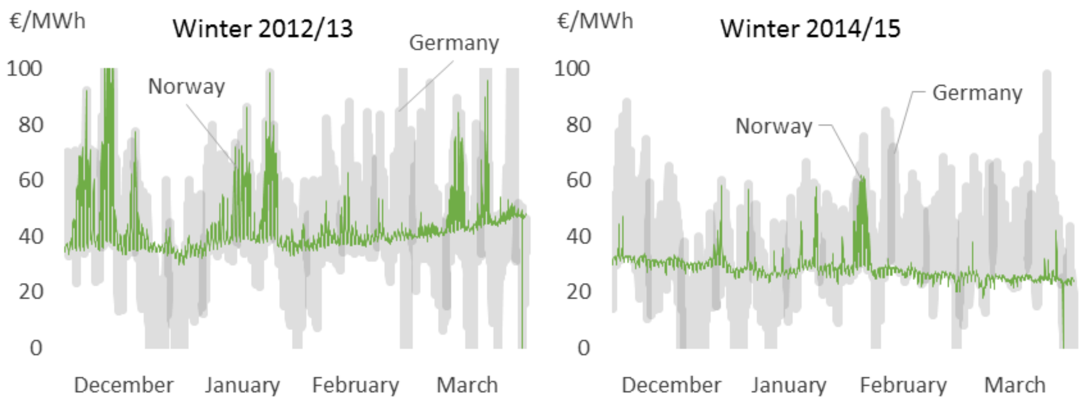

Figure 25. German and Norwegian (NO1) prices in the winters of 2012/2013 and 2014/2015.

Figure 25 illustrates the import of continental peak prices. The figure compares German and Norwegian hourly power prices in the winters of 2012/2013 and 2014/2015. We see that the level of German peak prices directly determines the level of Nordic price spikes. We also see the effect of weather. Import of continental peak prices occurred more frequently in the cold winter of 2012/2013 than in the mild winter of 2014/2015.

Energy-only results in higher and more frequent Nordic price spikes

Towards 2030, we expect more hours when available Nordic generation capacity is unable to meet both Nordic peak demand and full export on all interconnectors out of the region. There are two main reasons for this. The aggregated interconnector capacity under construction or in the permit process will increase the export capacity out of the Nordic region substantially. In addition, we expect the available Nordic generation capacity to decrease somewhat with decommissioning of nuclear reactors and continued development of renewables.

We have studied this expected Nordic development together with a continental energy-only market. The results indicate both a substantial increase in the level of Nordic price spikes and an upsurge in the number of hours with price spikes. As we have already discussed, the Nordic region occasionally imports continental peak prices directly. The radical increased level of continental price spikes in our energy-only scenario therefore naturally has an evident effect on Nordic price spikes. The upsurge in number of hours with Nordic price spikes has to do with the correlation in weather between the Continent and the Nordics. Our simulations, based on consistent weather series for 51 years, show that periods with high residual demand on the Continent often correlate with cold and dry periods in the Nordics.

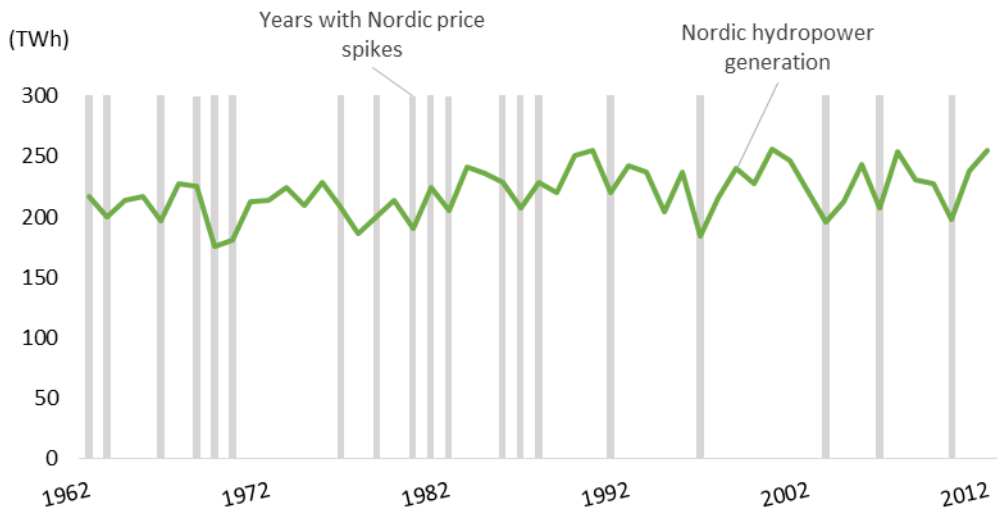

Figure 26. Nordic hydropower generation and occurrence of Nordic prices above 150 €/MWh over the simulated weather years.

Figure 27 shows the yearly amount of hours with price above 150 €/MWh in Norway for our reference scenario and three Nordic scenarios with energy-only as the continental market design. We have sorted the 51 weather years in descending order according to the amount of German hours above 150 €/MWh. Energy-only as market design on the Continent increases the number of hours with high prices in Norway. The pattern is most pronounced in years with low hydropower inflow, which had some hours with high prices also in the capacity market scenario.

The Nordic region is somewhat shielded from continental price spikes in our simulations, because of its power surplus and the limited interconnection capacity to the Continent. We have investigated a number of sensitivities in an effort to explore possible effects on the Nordic market of a continental energy-only scenario. We find that the amount of Nordic price spikes is very sensitive to changes in interconnection capacity between the Nordics and the Continent. Indicative simulations show that a 25 % increase in Nordic export capacity results in a near tripling of Nordic price spikes. This is also evident in Figure 27 where the increase between the “base” energy-only case and the case with increased interconnection capacity is larger than that between the “base” energy-only case and the case with capacity markets. When, in addition to increased interconnection capacity, we decrease the Nordic surplus, we see yet another rise in the number of Nordic price spikes.

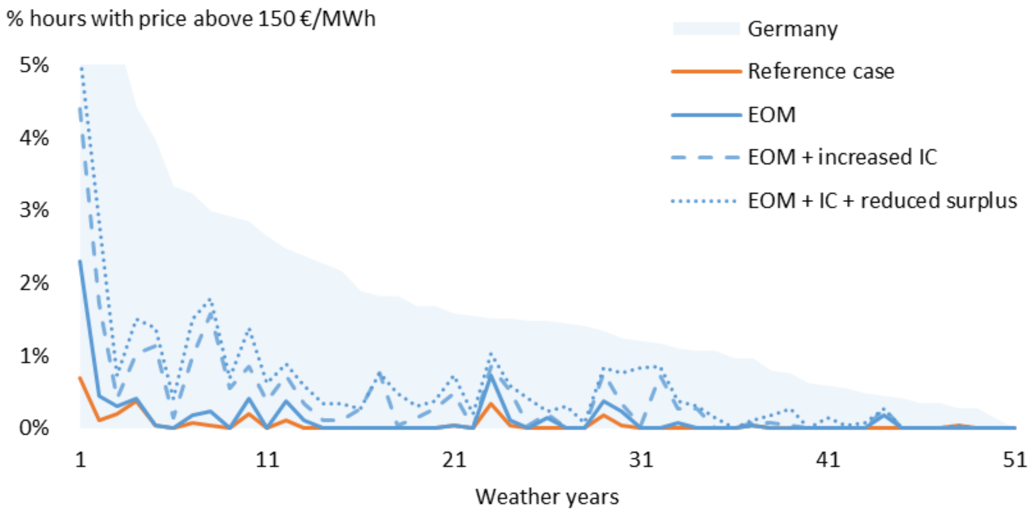

Figure 27. Percentage of yearly prices above 150 €/MWh for Norway and Germany in our simulations for 2030, sorted according to occurrence in Germany.

It is important to highlight here that the model we use for market modelling of the Nordic region underestimates periods of system tightness. That means it will underestimate the number of hours when there is not enough available generation capacity in the Nordics for regional demand and full export on all interconnectors out of the region. The model was originally developed for energy optimisation in a hydro system. It is therefore challenging to show the full effect on the Nordic region of a more volatile European market. We take part in several research and development activities to enhance our model park and modelling possibilities.

Increased competition for Nordic generation capacity

The willingness to pay for flexibility clearly increases with a tighter capacity margin. As we have seen in our analysis of the energy-only scenario, this will also feed through to the Nordic market. With an increased number of price spikes, reaching the cost of continental load shedding, it is possible that Nordic industry will also respond to the price and switch off production. Nordic demand-side flexibility will then offset the tight margin on the Continent. It is possible that flexibility on the Nordic side could react more frequently to strained situations on the Continent. The cost of Nordic load shedding will then become a ceiling for Nordic power prices.

It is difficult to discern the effects of this increased competition for available Nordic generation capacity. All the same, it is reasonable to expect a stronger drive towards increased demand-side flexibility, also in households and services, in a scenario with substantially more price volatility. More frequent and higher price spikes will also boost the investment case for power output extensions in hydropower and/or investment in pumping facilities.

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