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Le système électrique européen confronté à l'accord de Paris

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Avec la contribution d'Étienne Beeker

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Avant-propos

La transition vers un monde neutre en carbone et le développement des technologies – électrification des usages, numérisation, production décarbonée d'électricité, etc. – vont profondément modifier notre système énergétique. Pour éclairer cette évolution, et dans la suite des rapports publiés avec les mêmes experts sur le système électrique européen, France Stratégie a fait appel à trois économistes européens : Marc Oliver Bettzüge, professeur et directeur de l'Institut de l'économie de l'énergie à l'université de Cologne, Dieter Helm, professeur de politique énergétique à Oxford, et Fabien Roques, professeur associé à l'université Paris-Dauphine et vice-président de Compass Lexecon. Le constat est sans appel : nous devons repenser non seulement le marché de gros de l'électricité, mais également la régulation du système électrique.

Le consensus est désormais de plus en plus largement établi : le marché de gros actuel de l'électricité ne permet pas de déclencher de nouveaux investissements de production d'électricité pilotables. Pour atteindre les objectifs environnementaux qu'ils s'étaient fixés ou pour assurer leur sécurité d'approvisionnement, la plupart des pays ont recours à des mesures hors marché : soutien aux EnR pour plusieurs dizaines de milliards par an dans les pays de l'Union européenne, sortie administrée du charbon (après celle du nucléaire) en Allemagne, CfD au Royaume-Uni… Or, les différents États membres, en particulier l'Allemagne et le Royaume-Uni, ont besoin de réaliser dans les toutes prochaines années de nouveaux investissements, qui vont représenter des centaines de milliards, dans des moyens pilotables de production d'électricité ainsi que dans des moyens apportant de la flexibilité au système électrique. La commission allemande sur la sortie du charbon, en prenant position pour une fermeture de l'ensemble des centrales à charbon ou au lignite avant 2038, a ainsi souligné la nécessité pour l'Allemagne de disposer à terme d'un parc thermique de 50 GWe et de construire 20 GWe de nouvelles installations. En outre, les centaines de milliards de dépréciation des actifs dans la production d'électricité observées ces dernières années – de même que les modifications fréquentes d'une régulation complexe – conduisent fort logiquement les banquiers à considérer le secteur électrique comme risqué et à augmenter le prix de l'argent, ce qui conduit immanquablement à augmenter le coût pour le consommateur final.

Une première leçon de la libéralisation européenne du système électrique, conçue il y a une trentaine d'années, est que le marché ne produit pas spontanément les coordinations voulues et qu'il ne peut se substituer aux États dans les choix énergétiques. Cette libéralisation ne permet donc pas à l'Union d'affronter les enjeux énergétiques nécessaires à la transition vers la neutralité carbone et ne facilite guère la construction d'une politique énergétique européenne.

Une deuxième leçon réside dans l'incapacité du marché de gros non seulement à déclencher, mais aussi à bien orienter les investissements, qui forment l'essentiel des coûts de l'électricité, autrement dit à bien répartir les risques et à minimiser le coût d'ensemble pour la collectivité.

Ces leçons permettent d'esquisser les défis qui attendent la nouvelle Commission européenne et les différents États membres. Il appartient d'abord à ces derniers de programmer l'évolution de leur mix électrique en coopérant entre eux et avec la Commission et, en cohérence avec les objectifs énergétiques et climatiques de l'Union, d'inventer des mécanismes permettant d'atteindre ces objectifs, avec un nouveau partage des risques pour diminuer les coûts. Il leur appartient également de tracer, là encore en étroite liaison avec la Commission, le chemin d'une nouvelle architecture du marché européen de l'électricité. Cela suppose une évolution du rôle de la Commission européenne et de son rapport avec les États membres, avec à la fois plus de subsidiarité et plus de coordination. La révision des aides d'État que va mener la nouvelle Commission doit permettre le financement de nouveaux investissements, notamment grâce à des contrats de long terme : il peut constituer un premier pas vers un changement du logiciel et une refondation de l'architecture du système électrique.

C'est bien dans cette optique que les différents experts, chacun dans son style, nous invitent à nous interroger sur le cadre de régulation du système électrique. Conçue dans les années 1980 pour sortir des monopoles et permettre le développement d'une concurrence favorable au consommateur, cette régulation peut-elle nous emmener de manière optimale vers un monde neutre en carbone ? S'ils diffèrent sur le design d'une nouvelle régulation du système électrique, les trois experts se rejoignent sur plusieurs points. Ils soulignent la nécessité de réinstaurer une planification centrale couplée à une fonction d'achat, de faire reposer la concurrence sur des appels d'offres et d'instaurer des contrats de long terme comme principal instrument de déclenchement des investissements. Au-delà, leurs interrogations sont nombreuses. Comment repenser un marché de l'électricité qui ne permet pas de déclencher les investissements désirables ? Peut-on mettre en place à travers le marché du carbone un signal-prix crédible sur le long terme alors même que les fermetures des centrales à charbon vont le modifier profondément ? Dans ce nouveau système, où les *bottlenecks* présents sur les réseaux seront de plus en plus difficiles à résoudre, en particulier en Allemagne, ne faut-il pas envisager des instruments décentralisés de régulation ? Plus généralement, la répartition des niveaux de décision entre communauté, État et zones locales est-elle le plus adaptée ? Au-delà de la révision des aides d'État, la préparation d'une nouvelle régulation du système électrique adaptée à la transition énergétique que nous devons mener vers la neutralité carbone devrait ainsi être une priorité de la nouvelle Commission européenne.

Dominique Auverlot,
conseiller spécial, France Stratégie[1]

[1] Fonction occupée au moment des travaux.

Sommaire

Introduction
Le système électrique européen face au trilemme énergétique

par Dominique Auverlot, conseiller spécial, France Stratégie[2]

1. Le système électrique européen issu de la déréglementation : la loi du marché

Le marché intérieur de l'électricité de l'Union européenne, conçu dans les années 1990, reposait sur un principe simple : la concurrence, consécutive à la libéralisation du secteur, devait entraîner une baisse des prix de l'électricité pour les utilisateurs finaux – baisse qui allait profiter aux consommateurs.

Dans son fonctionnement quotidien, ce marché est une des réussites de l'Union de l'énergie. Le couplage par les prix entre les marchés journaliers des différents pays européens permet de disposer d'une production d'électricité au coût le moins élevé. Commencé en 2006 entre la France, la Belgique et les Pays-Bas, il concerne désormais la zone nord-ouest de l'Europe (North-Western Europe – NWE) et couvre l'Allemagne, l'Autriche, la France, la Belgique, les Pays-Bas, le Luxembourg, le Royaume-Uni, le Danemark, la Finlande, la Suède, la Norvège, l'Estonie, la Lettonie, la Lituanie et la Pologne (via la ligne SwePol), ce qui représente environ 75 % de la demande européenne d'électricité.

Le paquet climat énergie adopté par les Européens fin 2008 un an avant la conférence de Copenhague marque un tournant. Il ne se contente pas de déterminer la réduction des émissions à effectuer d'ici 2020. Au **trilemme énergétique** classique – soit le compromis nécessaire entre les trois objectifs : sécurité d'approvisionnement, minimisation des coûts pour préserver la compétitivité et le pouvoir d'achat, et protection de l'environnement –, il ajoute deux nouveaux objectifs liés au développement des énergies renouvelables et à l'efficacité énergétique. Il marque ainsi un premier retour de l'État prescripteur dans un secteur qui, conformément aux décisions adoptées une décennie plus tôt, devait être le jeu du marché.

[2] Aujourd'hui au ministère de la Transition écologique et solidaire, Dominique Auverlot a été conseiller spécial à France Stratégie jusqu'en avril 2019.

Bref historique de la dérégulation des systèmes électriques : de la libéralisation du secteur à l'intégration des énergies renouvelables intermittentes[3]

Pour faire face aux énormes investissements de la reconstruction d'après-guerre et profiter de très importantes économies d'échelle, le secteur électrique jusqu'alors assez parcellisé a connu une période de reconcentration très souvent accompagnée de nationalisations, y compris dans les pays de tradition libérale comme le Royaume-Uni ou les États-Unis. Cette organisation s'est faite autour de grands groupes ou de monopoles : EDF en France, CEGB au Royaume-Uni, ENEL en Italie, etc. Le système de l'Allemagne restera pour sa part très fragmenté même s'il est *in fine* composé d'opérateurs suprarégionaux importants (RWE, Preussen Elektra, etc.) appartenant souvent à des conglomérats (VEBA, VIAG, etc.).

Cette période qui s'étend jusque vers 1980-1990 est également celle du développement du système électrique européen qui aboutit à l'interconnexion physique de tous les pays du continent. Ce vaste réseau mis en place pour assurer la sécurité d'approvisionnement, le secours mutuel et déjà des échanges marchands d'énergie jette les bases d'une Europe « technique » de l'électricité.

C'est durant les années 1990 que l'Union européenne effectue une rupture de logique avec la volonté de mettre en place un marché intérieur de l'électricité conçu dans le prolongement de l'Acte unique dont l'objectif était l'achèvement du Marché intérieur. Celui-ci repose sur un principe simple – la concurrence, un outil que la Commission détient en propre et consécutive à la libéralisation du secteur, doit entraîner une baisse des prix de l'électricité qui profitera aux consommateurs – et un présupposé – l'électricité est un bien comme un autre qui peut s'adapter à des règles de marché.

Les années 1990 : l'heure britannique

La situation actuelle trouve ses prémisses dans le Royaume-Uni des années 1980 et la montée de la vision néolibérale portée par Margaret Thatcher. Alors que l'électricien historique, le CEGB, *Central Electricity Generating Board*, se trouve en mauvaise posture, d'importants gisements de gaz sont découverts en mer du Nord, et des nouveaux moyens de production, les centrales à cycle combiné au gaz, sont mises au point. La période autour des années 1990 voit ce pays être un des premiers, après les États-Unis, à libéraliser son système électrique en créant un marché et en séparant les acteurs en monopoles en divers acteurs privés. Rien ne se serait passé sans la volonté politique de Margaret Thatcher de briser les syndicats charbonniers, afin de remplacer le charbon, alors majoritaire dans la production d'électricité, par le gaz de la mer du Nord.

Les cycles combinés au gaz se caractérisant par une faible part d'investissement se prêtent bien à l'entrée d'investisseurs privés dans le secteur : la part du charbon dans la production d'électricité est réduite de 63 % à 38 % de 1990 à 2001 tandis que celle du gaz augmente de 1 % à 31 %.

La France et l'Allemagne s'opposent d'abord à cette vision, mais finalement cette dernière, voyant là l'opportunité de restructurer son secteur électrique, se range au côté du Royaume-Uni. La France isolée s'aligne finalement sur l'Allemagne et, fin 1996, après de longs débats, paraissent les directives européennes organisant la dérégulation du secteur. Peu de temps

[3] Par Étienne Beeker, France Stratégie. Une première version de cet encadré a été présentée par l'auteur lors de son intervention à Paris Dauphine le 22 novembre 2018 sur la régulation des marchés de l'électricité.

après, à la fin des années 1990, le Royaume-Uni[4] qui connaît les premiers dysfonctionnements de son système libéralisé, adopte une version moins stricte de la dérégulation en abandonnant l'obligation de recourir à la bourse de l'électricité qui permettait d'acheter et de vendre toute l'électricité produite et en recréant des opérateurs intégrés (incluant la production et le commerce de l'électricité).

Les années 2000 : entrée en vigueur de la dérégulation et intégration des enjeux environnementaux

La libéralisation s'étend au niveau européen dans les années 2000, entraînant le développement de centrales à gaz, porté par des coûts d'investissement faibles et des prix du gaz bas. La forte part des coûts variables entraîne une corrélation du prix de l'électricité avec celui du gaz, aboutissant à la baisse des prix espérée pour le consommateur. Mais rapidement le prix du gaz augmente fortement sous l'effet de la demande croissante, mais surtout du décollage de la Chine qui tire à la hausse les prix de toutes les matières premières.

Ces années 2000 sonnent également ce que l'on pourrait appeler l'heure allemande, avec une forte volonté de « verdissement » du mix et de développement des ENR électriques, ceci afin de répondre aux préoccupations environnementales de la population, mais aussi en grande partie pour répondre à l'augmentation des prix des énergies fossiles. Après quelques revirements, l'accident de Fukushima de 2011 a scellé la décision de l'Allemagne de sortir du nucléaire, à l'horizon de 2022 et de lancer son Energiewende (transition énergétique).

Au niveau européen, la Commission dispose de l'environnement comme compétence propre au côté de la concurrence. Elle érige le CO_2 comme principal critère de mesure des politiques environnementales et le développement des énergies renouvelables comme moyen d'en réduire les émissions. Ainsi naît le marché de quotas (dit « ETS ») en 2006 et le troisième paquet énergie de l'Union européenne de décembre 2008 (dit « 3 x 20 », pour 20 % de réduction de la consommation d'énergie, 20 % de réduction du CO_2 et 20% d'ENR en 2020).

La crise financière de 2008 est suivie de plans de relance qui font la part belle à la croissance verte. Les énergies renouvelables, soutenues par des tarifs d'achat très généreux, connaissent ainsi un important développement sans qu'il ait été jugé nécessaire d'une part de réviser l'architecture de marché de gros de l'électricité (alors que les EnR sont déjà rémunérées par ailleurs et qu'elles sont intermittentes), ni d'autre part de réviser le dimensionnement du marché

[4] Le lecteur trouvera plus de renseignements dans le rapport établi sous la direction de Dieter Helm pour le gouvernement britannique : Cost of energy Review, 25 octobre 2017. Voir notamment les pages 80 et suivantes : « *i) This model was jettisoned for two reasons, neither of which was convincing at the time. The first was the Austrian argument that compulsion was a 'bad thing', and that as the electricity industry moved towards a normal commodity market, the participants should be free to choose the most efficient trading arrangements, including by contracting outside the Pool in bilateral arrangements. The second was that the incumbent generators were gaming the Pool. 21. The first argument neglects the basic facts about electricity: that supply and demand have to be instantaneously matched, and that a merit order is a price discovery mechanism to ensure economic efficiency. All sorts of contracts could be written against the Pool, but the Pool could still play the central role. No other market arrangement could be so liquid (because everything had to go through the Pool), and therefore any other arrangement would be less liquid, and hence less efficient. It is no accident that after the Pool was abolished, Ofgem had to repeatedly intervene to ensure liquidity, including its most recent cash-out reforms. 22. The second argument is simply not a good reason for abandoning the Pool. It was the Pool that revealed the exercise of market power – transparently. The solution to this problem was to break up the market power. Instead the regulator allowed the generators to vertically integrate, and it was the combination of abandoning the Pool and vertical integration which increased market power, blocked off merchant entry, and cemented the role of the Big Six right through the first decade of this century. NETA, which effected these retrograde steps, was a mistake. It is not even entirely clear that the merit order was always preserved* ».

de quotas d'émissions de gaz à effet de serre alors que leur développement conduit logiquement à en réduire les quantités émises.

Les résultats de cette politique s'avèrent rapidement particulièrement décevants. Dans un rapport publié début 2014[5], France Stratégie constate que la dérégulation du secteur de l'électricité ne répond pas aux objectifs qui en étaient à l'origine. Les prix de l'électricité pour le client final augmentent en raison notamment des subventions hors marché qui lui sont répercutées ; ils ont par exemple doublé pour le consommateur allemand et ces subventions s'avèrent beaucoup plus élevées que prévu en raison de la chute du prix du baril de pétrole qui a suivi la crise de 2008 (où il avait culminé à plus de 140 dollars). De façon plus inquiétante, les prix de l'électricité en Europe sont aujourd'hui nettement plus élevés que ceux ayant cours aux États-Unis, avec une incidence forte sur la compétitivité des entreprises européennes. Si les émissions de CO_2 diminuent, c'est en raison principalement de la crise économique qui a sévi et de la désindustrialisation de l'Europe.

Quant à la sécurité d'approvisionnement, elle se trouve menacée par une plus grande dépendance aux importations d'hydrocarbures et d'équipements tels les panneaux solaires photovoltaïques (PV), mais aussi par une mauvaise intégration des énergies renouvelables intermittentes au réseau qui s'en trouve fragilisé. En effet, ces EnR sont implantées là où se trouvent les gisements de vent ou de soleil intéressants mais sans coordination avec le renforcement du réseau. Des congestions apparaissent, comme celles, emblématiques, entre le nord de l'Allemagne venté et producteur et le sud du pays industriel et consommateur.

Le retour inévitable d'une régulation étatique

Tandis que les prix de l'électricité pour les utilisateurs finaux augmentent, les prix de gros de l'électricité connaissent paradoxalement une baisse importante. Ils se révèlent incapables d'envoyer un signal suffisant pour déclencher les investissements de long terme ou indispensables à la sécurité du réseau. En particulier, ils conduisent à une perte de rentabilité des centrales de demi-base et de base – en général au gaz – nécessaires pour assurer la production pendant les périodes sans vent et sans soleil et assurer le *back up* des EnR.

Le rapport de France Stratégie, constatant que les objectifs classiques d'une politique énergétique – sécurité d'approvisionnement, préservation du pouvoir d'achat et de la compétitivité européenne, lutte contre les émissions de gaz à effet de serre – ne sont pas remplis, recommande de se focaliser sur la réduction des émissions de CO_2 et d'intégrer rapidement les EnR matures au marché en les soumettant aux règles communes. Il soulève également la question de la régulation du secteur électrique car depuis sa création, un marché libre de toute intervention n'a jamais vraiment eu le temps de fonctionner et de montrer qu'il délivrait les bons signaux aux acteurs du secteur pour investir à long terme. La première phase qui a commencé en 2002 a connu des prix bas en raison des surcapacités rémanentes qui étaient propres aux monopoles. Avant que ces surcapacités aient été résorbées a commencé la deuxième phase vers 2010, avec des quotas d'EnR à respecter. Des capacités supplémentaires ont été injectées, issues d'énergies renouvelables et les prix se sont à nouveau effondrés. Le débat persiste pour déterminer si le marché est ou non adapté au système électrique et les experts consultés ont sur ce point des avis divergents que l'on peut schématiquement regrouper en deux tendances :

− pour certains économistes, le marché européen intégré est encore entravé, en particulier par les plafonds de prix (*price caps*), qui empêchent de rémunérer les moyens de pointe. Complètement libéralisé, il devrait fournir des signaux-prix satisfaisants pour les

[5] France Stratégie (2014), *La crise du système électrique européen*, rapport.

investissements, grâce notamment aux signaux du marché à terme (à horizon de deux ou trois ans) ;

− pour d'autres, l'électricité est un bien particulier qui ne peut pas obéir à des règles de marché dans toutes les configurations et qui nécessite une régulation forte et une intervention des États.

Cependant, faire évoluer un édifice de cette complexité n'est pas chose aisée : il a ainsi fallu cinq ans pour que les énergies renouvelables intermittentes ne soient plus prioritaires sur le réseau lorsque les prix sont négatifs[6] !

Mais aujourd'hui, l'enjeu de la sécurité d'approvisionnement revient sur le devant de la scène et oblige les États à reprendre la main et à redevenir interventionnistes, ce que permet le traité de Lisbonne qui leur a accordé entière latitude dans le choix de leur mix énergétique. Les États adoptent par ailleurs une attitude ambiguë en entendant laisser faire le marché, tout en étant impatients de voir leurs objectifs se réaliser, tandis que la technologie et les marchés évoluent lentement.

Pour ce faire, la plupart des États mettent au point des mécanismes de capacité afin de soutenir les investissements dans les moyens de production nécessaires pour assurer l'équilibre offre-demande à moyen et long terme. Ironie de l'histoire, c'est le Royaume-Uni qui est le premier à mettre en place en 2014 un tel mécanisme, le CfD (Contract for Difference), une des raisons étant l'épuisement de ses champs gaziers de mer du Nord. L'Allemagne, après être sortie unilatéralement du nucléaire sur des critères politiques, met au point un mécanisme de réserve stratégique géré par le régulateur, la BNetzA. Elle s'oriente en 2019 vers une sortie administrative du charbon. La France définit en 2015 un marché de capacités plutôt complexe fixant des obligations aux fournisseurs.

Le retour à une régulation étatique semble difficilement évitable à court ou moyen terme. En effet, l'objectif de décarbonation requiert des investissements massifs, ainsi qu'une relation étroite avec la politique industrielle. La gestion des énergies renouvelables intermittentes est en outre très complexe et implique en particulier de tenir compte des fortes interactions entre la production et le réseau[7].

Mais faute de vision prospective commune, la politique énergétique communautaire se révèle incapable de coordonner tous ces mécanismes, ce qui engendre des surcoûts, voire menace la sécurité d'approvisionnement sur diverses parties du continent.

La crise économique et la baisse du prix des hydrocarbures ont eu trois conséquences. Premièrement, la valeur de la tonne carbone sur le marché d'échange de quotas d'émissions de CO_2 est restée très faible, en raison de la baisse de la production industrielle et d'un dimensionnement du marché de quotas ne tenant pas compte du déploiement des EnR et des efforts d'efficacité énergétique. Les différents acteurs du marché n'ont donc pas pu anticiper avec un degré d'assurance raisonnable les hausses de prix des quotas de CO_2, et ils n'ont pas été incités à s'orienter vers des investissements bas carbone.

[6] Ces périodes correspondent à une offre d'énergie plus importante que la demande, en général quand la production éolienne et/ou solaire est surabondante.

[7] Voir Beeker É. (2019), « Les réseaux de distribution d'électricité dans la transition énergétique », *Document de travail*, 2019-07, France Stratégie, novembre.

Deuxièmement, la rentabilité des énergies renouvelables devait être assurée très rapidement grâce au prolongement de la croissance du prix des hydrocabures observée de 2002 à mi-2008. Au contraire, la baisse de ce prix a conduit à une augmentation progressive du montant des subventions destinées au développement des EnR, même si le coût de l'éolien et du photovoltaïque a fortement baissé. D'où une hausse de la facture, notamment pour les Allemands, qui dépensent chaque année plus de 20 milliards d'euros pour rembourser le déploiement des énergies renouvelables dans le domaine de l'électricité.

La « désoptimisation » du système électrique constitue la troisième conséquence. La mise en place d'énergies renouvelables, prioritaires sur le réseau, conduit dans le cas de l'Allemagne à des achats hors marché de plus de 20 milliards d'euros, du même ordre de grandeur [8], sinon plus importants certaines années, que la valeur sur le marché de la totalité de la production d'électricité allemande (500 TWh à 40 €/MWh). Dans ces conditions, le système électrique s'éloigne de plus en plus des conditions de fonctionnement d'un marché optimal envisagées par Marcel Boiteux. Les dépréciations d'actifs des principales compagnies d'électricité ont atteint des dizaines de milliards d'euros sur les années récentes, en particulier pour les opérateurs historiques allemands RWE et E.On, mais aussi pour de nombreuses autres compagnies d'électricité. Qui plus est, le consommateur voit sa facture d'électricité augmenter !

Hormis certains projets décidés avant la crise, les investissements dans les moyens pilotables de production d'électricité se sont arrêtés. Avec de plus en plus d'énergies renouvelables subventionnées hors marché, les prix de gros ont baissé, l'électricité de semi-base est ainsi devenue de moins en moins rentable, ce qui a entraîné la fermeture temporaire ou le déclassement fréquent de centrales électriques, y compris de centrales neuves. Dans le même temps, les prix de gros de l'électricité sont devenus trop bas pour stimuler les investissements nécessaires. Enfin, le secteur de l'électricité n'est plus considéré comme rentable, ce qui se traduit par un coût du capital plus important, donc par des prix plus élevés pour les consommateurs et par une baisse de compétitivité des industries européennes.

Un système fondé sur le marché de gros de court terme ne permet pas de rémunérer la contribution des capacités de production au passage des pointes. Ce constat est apparu avec force à partir de 2010, lorsque s'est enclenchée la mécanique décrite ci-dessus, l'arrêt de nombreuses centrales thermiques soulevant des inquiétudes sur la sécurité d'alimentation du système électrique. Les différents États membres, conscients de ces difficultés et confrontés à une Commission qui ne souhaitait pas intervenir sur le sujet, ont dû mettre en place, sous des formes différentes et à défaut d'une solution commune, leur propre mécanisme pour garantir l'offre : marché de capacité centralisé au Royaume-Uni, marché de capacité décentralisé en France, mécanisme de réserve en Allemagne…

Cette situation n'était pas considérée comme critique il y a encore quelques années : certains économistes, allemands notamment, considéraient encore en 2014 qu'un véritable marché européen intégré et libéralisé de l'électricité pouvait, grâce notamment aux signaux du marché à terme (à horizon de deux ou trois ans), permettre de déclencher de nouveaux

[8] En particulier dans le secteur gazier.

investissements. Ce n'est plus le cas aujourd'hui. Le lecteur intéressé trouvera une analyse plus détaillée de ces phénomènes dans les rapports précédents de France Stratégie[9].

Durant ces différentes phases, un marché libre de toute intervention n'a jamais vraiment eu le temps de fonctionner et de montrer qu'il délivrait les bons signaux aux acteurs du secteur pour investir à long terme, alors que la sécurité d'approvisionnement est cruciale. La première phase qui a commencé en 2002 a connu des prix bas en raison des surcapacités rémanentes qui étaient propres aux monopoles. Avant la résorption de ces surcapacités a commencé la deuxième phase, avec des quotas d'EnR à respecter. Des capacités supplémentaires ont été injectées, issues d'énergies renouvelables, et les prix se sont à nouveau effondrés. Un débat persiste pour déterminer si le marché est oui ou non adapté au système électrique. L'électricité reste en effet peu ou prou un monopole naturel, pour les réseaux tout au moins. Ses coûts marginaux vont croissant, ce qui peut par exemple inciter les acteurs à pratiquer une rétention de capacités.

Les États adoptent par ailleurs une attitude ambiguë : s'ils entendent laisser faire le marché, ils sont soucieux de la sécurité d'approvisionnement, mais aussi de l'opinion publique. Ils sont impatients de voir leurs objectifs se réaliser, tandis que la technologie et les marchés évoluent lentement. Ils désignent les « bonnes » technologies (énergies renouvelables, éolien et photovoltaïque en tête) et les « mauvaises » (charbon, voire nucléaire). L'amont est en partie dérégulé, tandis que l'aval ne l'est pas – et ne peut donc pas répondre aux variations de prix. Les réglementations s'accumulent (ARENH, certificats d'économie d'énergie, réglementations thermiques, etc.). En d'autres termes, le marché fonctionne d'un point de vue « mécanique » mais ne remplit pas son rôle, obligeant les États à créer de nouveaux mécanismes pour soutenir les investissements, comme des marchés ou autres mécanismes de capacités. C'est oublier que puissance et énergie sont couplées. Sans mentionner la cacophonie européenne, puisque chaque État met en œuvre son propre mécanisme. La sécurité d'approvisionnement relève en effet de la subsidiarité des États.

2. Le retour de l'État prescripteur

Le défi auquel est confronté le système électrique européen ne consiste plus à construire et à étendre un marché européen de l'électricité destiné à appeler la centrale la moins chère sur la plaque européenne pour répondre à une demande supplémentaire d'électricité. Dans un contexte technologique en forte évolution qui conduit à imaginer désormais un système électrique reposant sur le numérique, sur des possibilités, certes limitées et coûteuses, de stockage de l'électricité, et sur des liens beaucoup plus étroits avec le local, cette étape a été franchie et peut être considérée comme accomplie. Le défi actuel de la décarbonation du secteur est différent : il consiste à reconstruire en partie le parc européen de production d'électricité pour le décarboner. En 2017, la production électrique de l'UE-28 reposait encore pour 45 % sur les hydrocabures et pour 21 % sur le charbon et le lignite. En l'absence de techniques efficaces de capture et de stockage du CO_2 et d'un stockage à bas coût de l'électricité, une réduction massive de nos émissions implique de fermer les centrales au

[9] France Stratégie (2014), *La crise du système électrique européen*, rapport ; et France Stratégie (2015), *L'Union de l'énergie,* Étude.

lignite et à charbon en les remplaçant par des EnR pour une part, mais aussi par des moyens de production pilotables et dans toute la mesure du possible décarbonés.

En Allemagne, la Commission pour la sortie du charbon (dont les conclusions devraient être traduites dans une loi) a affiché la nécessité d'un parc d'installations pilotables de 50 GW, ce qui la conduit à envisager la construction d'ici 2040 de 21 GW de nouvelles installations au gaz. Le Royaume-Uni de son côté envisageait un besoin de 13 GW de nucléaire à l'horizon 2030 (pour remplacer ses centrales actuelles) et la France devra dans les prochaines années garder une part d'électricité pilotable pouvant la conduire à envisager de construire de nouvelles installations de production d'électricité.

Durant l'été 2018, France Stratégie a lancé une réflexion non seulement sur le devenir de l'Europe de l'électricité, mais plus généralement sur les régulations nécessaires dans le domaine de l'énergie pour une transition vers un monde neutre en carbone. France Stratégie a fait de nouveau appel à trois économistes, allemand, britannique et français :

- **Marc Oliver Bettzüge**, professeur d'économie à l'université de Cologne, directeur général et président du conseil d'administration de l'Institut de l'économie de l'énergie (EWI) de l'université de Cologne ;
- **Dieter Helm**, professeur de politique énergétique à l'université d'Oxford et chercheur en économie au New College à Oxford ;
- **Fabien Roques**, professeur associé à l'université Paris-Dauphine et *senior vice president* à Compass Lexecon.

Leurs réflexions sont présentées dans les différentes sections de ce document. L'introduction quant à elle ne relève pas de leur responsabilité.

De leurs travaux se dégage un consensus sur la nécessité de revoir l'organisation du marché de l'électricité. Nous entrons dans une nouvelle phase du marché, marquée par un coût marginal de production de plus en plus fréquemment proche de zéro, ainsi que par un besoin d'investissements importants dans des moyens de production pilotables.

Les trois experts se rejoignent désormais également sur l'idée que le marché de gros de l'électricité ne permet pas de déclencher les investissements de long terme. Ce consensus est de plus en plus largement partagé : il figure notamment dans le dernier rapport de l'Agence internationale de l'énergie[10] ou dans les écrits récents de certains universitaires américains, pourtant acquis aux vertus du marché[11].

Dès lors que le système électrique et l'Allemagne en particulier ont besoin d'investissements importants pour décarboner leur production et que le marché ne permet pas leur déclenchement, deux conclusions s'imposent :

- le retour d'un État prescripteur qui doit définir les investissements nécessaires et les déclencher, ce qui suppose qu'il s'en donne les moyens ;

[10] International Energy Agency (2018), World Energy Outlook 2018.

[11] Joskow P. (2019), « *Challenges for Wholesale Electricity Markets with Intermittent Renewable Generation at Scale* », December 2018, MIT CEEPR, *Working Paper Series*, n° 2019-001.

– la mise en place de mécanismes économiques permettant ces investissements : la révision des aides d'État initiée par la Commission doit ainsi avoir pour but d'autoriser ces mécanismes dans le cadre du design actuel du marché électrique. Le *Contract for difference*, qui garantit un tarif d'achat, ou le *Regulated Asset Base (RAB)*, qui accompagne le futur producteur dans ses dépenses d'investissement, sont deux exemples typiques d'une contractualisation de long terme souhaitable qui permet d'effectuer un meilleur partage du risque et, au total, de minimiser les coûts pour la collectivité.

3. Quatre conséquences

Cette nouvelle phase du marché privilégiant la décarbonation repose naturellement la question des *trade-offs* entre les différentes composantes du trilemme énergétique. Elle va entraîner un certain nombre de conséquences, que ce soit sur la sécurité énergétique du secteur de l'électricité (*via* l'équilibre offre-demande) ou du secteur gazier (*via* les approvisionnements en gaz), mais également sur la compétitivité des entreprises et le pouvoir d'achat. Elle nécessite enfin un meilleur couplage des énergies, notamment entre l'électricité et le gaz (qui permet de produire de l'électricité en cas de tension sur le réseau électrique) et entre l'électricité et la chaleur.

En outre, la numérisation du système électrique va permettre la transmission aux clients de signaux prix et une gestion beaucoup plus active de sa consommation électrique par le consommateur. Nécessaire pour limiter les pics de demande associés à l'essor du véhicule électrique ou pour combler les creux de production des énergies renouvelables, cette gestion devrait modifier la courbe de charge de la demande d'électricité à la pointe et ainsi notre approche des mécanismes de capacité.

Le nouveau paradigme de la sécurité énergétique

- *La sécurité du système électrique* : l'Allemagne vise désormais, conformément au contrat de coalition adopté en mars 2018, une part de 65 % d´énergies renouvelables dans sa consommation d´électricité à 2030[12]. Mais, en l'absence de moyens efficaces de stockage, elle estime également nécessaire de disposer d'un parc conséquent d'installations pilotables de production d'électricité pour répondre à la demande d'électricité en hiver. Pour pouvoir fermer les 9 GW de nucléaire encore en fonctionnement ainsi que les 40 GW de centrales au charbon ou au lignite présentes sur le territoire allemand, la Commission sur la sortie du charbon préconise de mettre en place un parc de production thermique d'une puissance de 50 GW, ce qui suppose de construire 21 GW d'installations supplémentaires de gaz. L'économiste Hans Werner Sinn[13] qualifie de manière schématique cette évolution comme la mise en place d'une double structure du parc de production d'électricité : un parc à base de renouvelables lorsqu'il y a du vent et du soleil ; et un parc destiné à assurer la production complémentaire lorsque les conditions météorologiques sont défavorables à la

[12] En supposant que la production d'électricité renouvelable est entièrement utilisée pour la consommation.
[13] www.hanswernersinn.de/dcs/2017%20Buffering%20Volatility%20EER%2099%202017.pdf

production d'électricité renouvelable et que le stockage de l'énergie ou l'effacement de la consommation ne permettent pas de répondre à la demande.

Cette vision « pragmatique » à moyen terme du parc de production d'électricité est très différente non seulement de la vision optimisée traditionnelle d'un parc de production d'électricité, mais aussi de celle qui ressort de l'exercice 2016 de prospective de l'Ademe envisageant une production d'électricité à 100 % d'origine renouvelable.

La sécurité de l'approvisionnement en gaz : une des conséquences – au moins en Allemagne – de la fermeture des centrales au charbon consistera en une plus grande consommation de gaz, avec une dépendance accrue au gaz russe. Si certains le regrettent, Dieter Helm en tire quatre conclusions, en se plaçant dans la continuité des travaux de la Commission européenne et de la révision de la directive sur la sécurité d'approvisionnement en gaz. Pour lui, il est nécessaire de renforcer les interconnections gazières ; d'améliorer l'application du principe de solidarité entre les États membres ; et de faciliter la revente du gaz entre les États membres.

Ce paragraphe sur la sécurité d'approvisionnement en gaz illustre là encore l'intérêt d'une politique énergétique européenne, à laquelle le marché ne peut se substituer.

Pouvoir d'achat ou réduction des émissions de GES

L'exemple des gilets jaunes en France montre que l'augmentation du prix des énergies liée à la volonté de réduire les émissions de carbone peut être pénalisante pour le pouvoir d'achat des ménages. De fait, cette pénalisation peut intervenir par l'augmentation du prix des carburants, l'augmentation du prix de l'électricité (liée à la CSPE), l'augmentation des impôts liée aux dépenses des énergies renouvelables non prises en compte dans le cadre de la CSPE, etc.

En Allemagne, la Commission sur la sortie du charbon s'est heurtée à deux problèmes : la préservation de la compétitivité des industriels allemands qui vont être soumis à un coût de l'électricité plus élevé, ainsi qu'aux compensations à accorder dans les zones de l'Allemagne de l'est touchées par la fermeture des installations – compensations directes aux salariés des installations en cours de fermeture ou aux collectivités concernées, mais également compensations indirectes à l'égard des personnes qui bénéficiaient de l'activité économique ainsi mise en place (y compris à l'égard des clubs sportifs sponsorisés par de telles activités). Dans son rapport final, la Commission se prononce en faveur de mesures permettant de ne pas augmenter le coût de l'électricité pour les ménages ou pour les industriels et prévoit la mise en place de fonds à cet effet.

Le nécessaire couplage des énergies

Cette nouvelle phase va se traduire par le besoin renforcé d'étudier complémentarités entre différentes sources d'énergies et infrastructures permettant le couplage des énergies : c'est l'idée notamment défendue par Fabien Roques dans le chapitre qu'il a rédigé. Le gaz vert et/ou l'hydrogene permettront ainsi d'absorber les excès de production d'électricité décarbonée quand la demande est faible et de la transporter/stocker. Par ailleurs, il conviendrait de reconnaître comme prioritaire l'usage du gaz pour la production d'électricité dans les situations de tension (ce que ne prévoit pas explicitement la dernière directive sur la sécurité d'approvisionnement en gaz).

Le couplage intersaisonnier entre l'électricité et la chaleur, notamment dans le résidentiel, possède par ailleurs un très large potentiel de développement.

De manière plus prospective, l'un des couplages possibles en Allemagne entre gaz et électricité consisterait à produire du gaz (hydrogène, voire méthane) à partir de l'électricité et à réutiliser celui-ci pour répondre à la demande notamment en hiver. Ce schéma est *a priori* coûteux et relève donc aujourd'hui du domaine de la prospective : le BDEW demanderait de baisser le prix de l'électricité qui serait ainsi utilisée (en réduisant les taxes correspondantes) afin d'obtenir une électricité qui puisse être compétitive par rapport aux énergies fossiles : c'est pour le BDEW « une condition préalable fondamentale pour économiser davantage de CO_2 dans ces domaines également ».

Les frontières entre GRT et GRD, et entre GRD et consommateurs s'estompent de plus en plus…

Dans cette nouvelle phase du marché où les énergies renouvelables peuvent faire remonter leur électrons jusqu'au réseau de transport et où les données doivent s'échanger sur l'ensemble du système, la frontière entre les réseaux de transport et de distribution devient de plus en plus ténue. Cela conduit soit à repenser l'articulation de ces deux fonctions, soit, comme l'évoque Dieter Helm, à reposer la question de leur unification.

En outre, le développement de la production locale, du stockage local de l'électricité (notamment dans les véhicules électriques) et des technologies numériques permettant d'effacer le moment venu certaines consommations renforce l'intérêt des synergies à trouver entre l'investissement dans de nouvelles lignes de distribution et la gestion locale de l'énergie et accentue la nécessité d'un dialogue local renforcé.

4. Quatre visions du marché électrique des années 2030

Si la révision des aides d'État s'impose pour déclencher les investissements dans le court-moyen terme, on peut néanmoins envisager à dix ans la mise en place d'un nouveau fonctionnement du marché électrique afin de permettre une rémunération de l'ensemble des investissements nécessaires à son fonctionnement.

S'ils diffèrent sur les modalités de la mise en œuvre, les experts se rejoignent néanmoins sur plusieurs points. Ils soulignent en particulier la nécessité de réinstaurer une planification centrale couplée à une fonction d'achat, de faire reposer la concurrence sur des appels d'offres et d'instaurer des contrats de long terme comme principal instrument de déclenchement des investissements.

Dans ces conditions, quatre visions du marché peuvent être envisagées à 2030 :

- la première consiste, dans une solution de facilité, à prolonger le système actuel. Elle présente au moins trois avantages : i) le marché actuel fait appel à la centrale d'électricité dont le coût marginal est le plus bas et minimise le coût marginal de production, ii) il a permis le développement des EnR et un léger repli du charbon, iii) enfin, l'augmentation des prix du charbon et du gaz ainsi que la valorisation plus importante du quota de CO_2 désormais autour de 20 €/tCO_2 ont permis de redonner une certain vigueur au marché de l'électricité qui retrouve des valeurs voisines de 60 €/MWh. Le marché actuel peut donc permettre le déclenchement de certains investissements décarbonés. Mais, double inconvénient, cette hausse des prix (y compris la hausse de la valeur carbone sur le marché ETS) peut n'être que temporaire et, de plus, elle n'offre pas de rentabilité supplémentaire pour la production d'électricité à base de gaz ;

– **Dieter Helm** propose, dès lors, une refonte complète de ce marché par la mise en place d'un acteur central qui achète l'électricité sur la base d'appels d'offres portant sur la puissance garantie des différentes installations de production. Le lecteur intéressé par cette proposition pourra trouver un éclairage complémentaire dans la revue des coûts de l'énergie que Dieter Helm a mené pour le gouvernement britannique en 2017[14] ainsi que dans les nombreuses réponses qui figurent sur Internet à la consultation lancée sur ce texte par ce même gouvernement[15];

– **Fabien Roques** met en avant un modèle de marché organisant une concurrence en deux temps, avec une concurrence « pour le marché organisée autour d'appels d'offres pour des contrats long terme suivie d'une concurrence » dans le marché permettant d'assurer un *dispatch* optimal. Il décline les implications en termes de gouvernance et de planification d'un tel modèle qui permettrait de résoudre les incohérences du cadre actuel entre le design de marché et les interventions politiques pour déterminer le mix et les investissements ;

– **Marc Bettzüge** constate qu'il est nécessaire de changer les règles de *l'Energy Only Market* pour pouvoir financer de nouvelles installations de production et envisage des garanties d'État permettant d'assurer leur rentabilité.

Dans tous les cas, comme l'envisage le texte ci-dessus, des aides d'État devront être permises dans le court terme pour financer de nouvelles installations de production, ce qui rejoint la préoccupation de la Commission d'actualiser le cadre d'analyse des aides d'État qui lui permet de les reconnaître compatibles, ou non, avec le Traité fondateur de l'Union européenne.

5. Inventer les régulations nécessaires à la transition vers un monde neutre en carbone

Au-delà de la remise en question du fonctionnement du marché actuel de l'électricité, les trois experts nous interrogent cependant plus fondamentalement sur les régulations à mettre en œuvre dans le secteur de l'énergie pour en permettre la décarbonation :

[14] https://www.gov.uk/government/publications/cost-of-energy-independent-review
[15] https://www.gov.uk/government/consultations/cost-of-energy-review-call-for-evidence

- les objectifs de réduction des émissions de gaz à effet de l'Union européenne ne sont pas en phase avec ceux de l'accord de Paris qui prévoit la neutralité carbone de la planète dans la seconde moitié de ce siècle, ce qui conduit à nous réinterroger sur nos ambitions à 2040. Dans son discours devant le Parlement européen le 16 juillet, la Présidente de la Commission, Ursula von der Leyen, a ainsi envisagé de rehausser l'objectif européen de réduction des émissions à 2030 pour le porter à 50 %, voire 55 % (par rapport à 1990) et a affiché son soutien à l'atteinte de la neutralité carbone en 2050 ;

- de telles ambitions remettent en cause toute idée de concurrence loyale entre des industriels qui y seraient soumis et d'autres qui pourraient s'en affranchir, ce qui repose la question des outils permettant de préserver l'industrie européenne, depuis la mise en place d'une taxe carbone jusqu'à la suspension des échanges avec les pays qui ne respecteraient pas l'accord de Paris ; Fabien Roques recommande ainsi de tester les politiques énergétiques et climatiques envisagées à l'échelle européenne dans des scénarios où les prix des énergies resteraient bas et dans des scénarios où la coopération mondiale dans la lutte contre le changement climatique serait faible ;

- le marché du carbone n'a pas permis de donner de signal-prix du carbone sur le long terme si bien que, malheureusement, à de rares exceptions près, les investisseurs ne tiennent pas compte du carbone dans leurs décisions qui engagent l'avenir : Fabien Roques propose donc d'adjoindre un prix plancher du carbone qui sur le long terme permettrait de donner un signal-prix ; Marc Oliver Bettzüge (en oubliant peut-être les difficultés rencontrées par la France dans la fixation de telles valeurs) va plus loin en proposant de remplacer le marché par une taxe… Il étend son questionnement à l'accord de Paris lui-même : ne faudrait-il pas faire porter les négociations entre les pays, non pas sur les quantités de réduction d'émissions, au risque d'aboutir à un effort mondial insuffisant, mais plutôt sur une valeur du carbone à appliquer par les différents pays ?

- Fabien Roques et Marc Oliver Bettzüge insistent enfin sur l'importance du couplage des énergies nécessaire à la transition, et posent la question des régulations à mettre en œuvre à cette fin : une gouvernance à la maille locale des réseaux et de leurs *bottlenecks* serait ainsi à envisager (en particulier en Allemagne) pour Marc Oliver Bettzüge.

6. Six priorités pour l'Union de l'énergie

De ces réflexions ressortent six priorités pour le prochain mandat de la Commission et du Parlement dans le domaine de l'énergie :

- rehausser les ambitions climatiques de l'Union européenne en veillant à protéger sa compétitivité industrielle : l'adoption de ces objectifs suppose cependant que soient définies préalablement les régulations économiques qui vont permettre de les atteindre, que soient évalués leurs impacts et que soient mises en place les mesures redistributives nécessaires non seulement à l'intérieur des pays, mais aussi entre les États membres de l'Union européenne ;

- créer à court terme de nouveaux mécanismes d'aides d'État permettant la réalisation de nouveaux investissements de production pilotable d'électricité ;
- lancer une réflexion sur ce que devrait être un marché de l'électricité à l'horizon 2030 permettant la rémunération des investissements ;
- retrouver une vision industrielle du secteur énergétique, conduisant l'Union européenne à protéger son tissu industriel vis-à-vis d'autres acteurs qui ne seraient pas soumis aux mêmes contraintes : l'utilisation du véhicule électrique ne peut être considérée comme satisfaisante que si la production de sa batterie s'effectue dans un mix électrique en grande partie décarbonée. Il faut donc chercher à avantager les fabricants de batteries qui s'adossent à une énergie décarbonée ;
- renforcer la solidarité européenne entre les États membres ainsi qu'à l'égard de l'Ukraine (dans la suite des négociations au format Normandie) ;
- définir les régulations énergétiques nécessaires à la transition vers un monde neutre en carbone

Chapter 1
European energy market developments to 2050: an overview

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28th January 2019

To a much greater extent than many national and European politicians imagine, Europe's energy markets are shaped by changes in the underlying economic and geopolitics fundamentals. Policies have their impacts in this context, and their success or failure depends in large measure whether they go with the grain.

This paper starts with the economic fundamentals – the oil and gas markets, digitalization and new energy technologies. These matter more than any other factors under consideration, and yet are typically either simplistically assumed away or ignored (section 1).

Geopolitics for Europe is very much about Russia, Russian gas supplies and Russian-driven developments in the Baltics, Ukraine and Poland (section 2). The main specific policies in Europe relate to its climate change ambitions and the future of the IEM (section 3). The missing bits are on security of supply and capacity markets (section 4). Together these considerations point the way forward for European energy policy (section 5).

1. The economic fundamentals

There are four changes to the fundamentals, which should inform the design of European energy and climate policies: in the fossil fuel markets; in digitalization and the growth of the electricity share in final energy demand; in heat and hydrogen; and in the electrification of transport.

1.1. Oil, gas and coal

The demand for energy is a derived one. Energy has little value in itself: it is the means to power the industrialized economies of the world. That energy is and remains overwhelmingly derived from burning fossil fuels, and political rhetoric and global agreements have so far made little or no impact on this global dominance.

As global demand has been going up, so too has the coal burn, notably in China, India and Africa. Oil demand growth has slowed, but gas is rising strongly, again in the three areas of greatest global economic growth – China, India and Africa.

Notwithstanding the growth in energy demand, supplies have been expanding to meet and even exceed demand. World oil supplies are being boosted by record production in Russia, the US and Saudi Arabia. All comfortably exceed 10 mbd. This trend is likely to continue, since the central thesis of *Burn Out*, that oil prices can be expected *to fall* in the medium and longer terms, has fed through to the recognition amongst the big producer countries that oil today is worth more than it probably will be in the future. Couple this with the national budgetary constraints, kicked off by the fall in prices in late 2014, and oil production is likely to be sustained. Having recovered toward $80 a barrel, oil prices have since fallen back sharply. Lower and falling oil prices will encourage demand to increase.

Gas supplies have increased too. The reasons are related to the shale gas revolution in the US, and the coming on stream of major new supplies, notably in Australia. The Qatar LNG fields were developed very much with the US market in mind. Now that the US is no longer a significant importer, and has indeed switched to exports, notably for ethane, Qatar's exports are additional to the baseline expectations. With Australia coming on stream to meet primarily East Asian demand, and with new pipelines from Russia to Europe, gas's role in meeting total energy demand is likely to rise. Part of this rise will be at the expense of oil: ethane provides a gas-derived base for petrochemicals; and gas for hydrogen and gas for electricity cut into the demand for oil for transport. As gas replaces oil, the oil price may fall further.

On coal, China is adding some 250GWs of new coal fired power stations, as well as financing over 200 coal power stations abroad. Germany's exit over 2 decades will not make much global difference.

There are no credible forecasts that suggest that the absolute levels of oil, gas and coal burns will fall before 2040 at the earliest, and hence when combined with the growing coal burn and the greater demand for gas, all these forecasts suggest the world is not on the IPPC recommended trajectory.

1.2. Digitalization and the growth of electricity demand

The second fundamental relates to digitalization and the growing role of electricity. These changes include robotics, 3D printing (additive manufacturing, big data and smart systems and meters, and AI). Almost everything that is digital runs on electricity. This implies a greater role of electricity for final energy demand. The energy policy questions that arise are about the fuel sources of generating the electricity.

1.3. Heat and hydrogen

The third fundamental relates to heat and the possible roles of hydrogen. Again the policy issues relate to the fuels used to make hydrogen. This could come from renewables electricity generation, notably wind, or from gas. From a climate change perspective the gas would require CCS.

1.4. Electrification of transport

Electric cars are gradually coming into the transport market, and there are a host of forecasts that suggest a rapid transition away from the internal combustion engine. However, the economic competitive advantage of conventional engines, and the intermediate technologies around hybrids, indicate that there will need to be a series of technological breakthroughs plus very high carbon prices to effect this transition. Whether a switch to electric vehicles reduces emissions depends on how the electricity is generated. The electrification of trucks and freight and aviation are still at best emerging technologies and it is unclear how the move from fossil fuels will pan out globally by 2050.

The role of hydrogen and fuel cells in transport depends upon the distribution networks for the fuels. The development of the necessary networks, and their coordination, is in its infancy.

In summary, the emerging economic context for 2050 is of falling oil prices, more gas, and electricity as a growing share of final energy demand. It remains an open question as to what role if any hydrogen will play, both for transport and heating.

2. Geopolitics and European energy

European energy policy is set in a geopolitical context, in respect to security of supply and carbon emissions. European external security of supply primarily relates to Russia. For carbon emissions, recognizing that climate change is a global matter, the main policy concerns lie with China, India, Africa, Brazil and the US.

The relationship between Europe and Russia has deteriorated over the last decade. A series of events, from the annexation of South Ossetia and Abkhazia, to the interruptions on gas supplies in 2006 and 2009, through to the annexation of Crimea and the active involvement in the war in eastern Ukraine, have weakened the political reliability of Russia as a core gas supplier to Europe. The situation in Ukraine can be expected to worsen in 2019, and looking through to 2050, Russia's ambition to bring Ukraine back under Russian control heralds a series of military interventions, often using unconventional warfare.

Further actions by Russia in the Baltics and in Scandinavia, including cyber attacks and violations of territorial waters, and Nordstream 1 and then Nordstream 2, have all contributed to more doubt about the wisdom of Europe relying on Russia and heightened expectations that Russia will use energy as a strategic and political tool in its attempts to gradually revise the post-1991 borders of Russia in Europe.

These growing tensions are likely to take a sharp turn for the worse when the Ukrainian gas contracts expire in December 2019, and as and when Nordstream 2 allows Russia to bypass Ukraine. For Russia, Ukraine is "unfinished business" and the gas pipelines are key pawns in its strategy.

Finally in regard to Russia, the European populist movement is bringing to power governments supported by political parties who take a decidedly more pro-Russian line. Italy is the latest example, and the May 2019 European elections may reinforce this element in the European parliament and make further progress of European energy security policies much harder to develop and implement. This fits in with a gradual re-nationalization of energy policy by EU members states back form the Commission.

On climate change, the coming to power of Trump and Bolsanaro are but the latest steps away from a UN-led climate change agreement framework. The Paris Agreement is making little headway, and there is little chance that the 2 degrees limit will be achieved as a result of Paris. The 1.5 degrees target is probably wishful thinking, introduced in part to cover up the fact that the pledges at Paris did not add up to the 2 degrees target requirements.

The future of climate change mitigation will lie with the global autocrats and populists, not with those EU members who wish to take unilateral actions. Indeed post the May 2019 European elections, it is not even clear that the Europe-wide framework will continue in its current format.

3. Europe's objectives and energy and climate policies

It is against this deteriorating geopolitical background that Europe's energy policy needs to be set, not some idealized world of a liberalizing democratic Russia or a global cooperative enthusiasm to do much about climate change. Current European energy policy is not fit for either the security of supply or the climate change objectives, to the extent that these are properly specified, rather than being "ambitions".

On security of supply, and given the gradual shift toward electricity, the main building blocks are in two parts: in gas; and in electricity capacity.

3.1. Gas security

Gas security is of rising importance because the Netherlands and North Sea gas fields are running down. Domestic production plus Norway will gradually make up less of the EU's supplies. This leaves three options: Russia (the dominant supplier); southern pipelines; and LNG.

Having experienced interruptions in supplies, and mindful of Russia's aggressive stance against Ukraine, there are several routes to a more secure gas position in Europe. The obvious one is to reduce supplies from Russia, but this comes up against price and costs. Russian pipeline gas is very competitive. So the task is to come up with ways of getting the price advantage, whilst limiting the exposure to interruptions to any and all EU members.

The latter could be achieved in a number of ways. First, the EU markets could be better interconnected directly for gas, and indirectly by greater electricity interconnectors. Second, the solidarity principle could be enhanced, so that all EU members states stand ready to take pre-defined measures to ensure no member is exposed. Third, resale requirements on common prices could be fully and completely implemented. Fourth, there could be an explicit commitment to protect and support Ukraine in the face of actions post December 2019 to radically reduce or even cut of the Ukrainian pipeline supplies.

Some in Europe argue that the EU should go further and stop the Nordstream 2 pipeline. This pipeline is not strictly needed, and it is obvious that, together with earlier and so far unsuccessful South Stream, part of Russia's strategy to isolate Ukraine. Further, it goes around the outside of the Baltics and Poland, leaving these former eastern European countries more exposed to Russian pressures. This is especially the case for Poland, which faces the challenge of reducing its coal industry to meet the EU's climate ambitions. Given that the German government is reluctant to break its "special relationship" with Russia, derived from a very long historical experience, and because it will require more gas to displace the closure of coal fired generation, the full implementation of the steps outlined above is urgent.

3.2. Climate change

The news on climate change is grim. Since 1990 there has been a continuous rise in the concentration of carbon in the atmosphere. Kyoto made no difference and, being a European endeavour, it may have exacerbated emissions by giving a competitive advantage to Chinese and other energy intensive exporters.

At Paris, there was no legally binding Treaty (and hence it failed to meet the ambitions set at Durban), and the pledges even if met (which is unlikely) will lead to global warming well in excess of 2 degrees. Having broken through the 400 ppm level, the world is well on its way to 500 ppm.

In the post Paris period, several aspects have got worse. First, as the world's largest polluter, China's emissions in 2017 rose by 17%. China is reported to approaching 1000GW of coal fired electricity generation; also, as noted above, it is building another 250GWs; and it is financing about 200GWs of coal aboard. Second, China is pushing for the Paris agreement to reinsert the Kyoto division between developed and developing countries, with itself classified as developing. Third, China's return to autocracy and away from private markets may present a greater priority to political stability around short term economic growth over longer term benefits to the climate. Jobs and economic interests in coal may trump climate change concerns. Indeed there is some evidence they already have. Fourth, the other main actual and potential polluters – the US, India, Africa and Brazil – have either taken no serious mitigation steps or are actively making their ability to do so worse.

Trump is promoting coal, and stays outside the UN-led framework (as did Clinton, Bush and Obama). Brazil's new populist leader is weakening protection for the Amazon. India and Africa are ploughing on with 6-8% GDP growth per annum, and in both cases relying on fossil fuels. Africa too is likely to lose carbon from its soils and the depletion of its rainforests.

At some point it will dawn on Europe that climate change will only be mitigated by engaging with these major polluters, and its own unilateral targets are not going to make much difference, if any, on their own. The most important issue for European climate mitigation policies is to make sure that its unilateral targets do not make things worse, and this requires that there is a border carbon adjustment to put imports and domestic production on level playing field. Failing to introduce a border carbon adjustment will not make the problem go away.

With this in place, the policy question is then: *what can Europe do which helps reduce global emissions?* The answer to this is overwhelmingly bottom up and driven by technology. Top down UN-led initiatives are not going to work in the necessary time frame, and existing renewables will not do the job. If Europe remains reluctant or even hostile on nuclear (and with the UK pulling back on nuclear now too), then new technologies are necessary. Given that Europe spends far more of its consumers' monies on "low carbon" than any other economy, the scope for diverting some of the current spend into R&D is very large.

3.3. The IEM

The Internal Energy Market (IEM) has had a tortured history. Its origins lie in the optimism that flowed from the wider Completing the Single Market initiative following the 1987 legislation. Adding on energy (and other infrastructures) was a logical extension in the great age of late twentieth century capitalism.

The IEM's model was built upon the British privatisation programme, and the belief that commodity markets and competition would solve the electricity and gas market problems, and in particular would ensure both competitive prices and security of supply. The subsequent quarter of a century has been spent trying to implement this British model. Along the way, third party versus regulated access, legal versus ownership unbundling, and the role of the state versus private ownership have provided the scripts for intense debates, political battles and European legislation.

The IEM was conceived of as a project prior to and independent of climate change. Climate change policies have been implemented largely outside the IEM and have gradually undermined it. The climate change policies have returned Europe to regulated third party access by giving priority to renewables over other technologies, begun to undermine the simple –and simplistic – unbundling and been driven by the state and state contracting rather then IEM-type markets. The result is that almost all new generation is either explicitly or implicitly dependent on government contracting rather than private markets, and the idea of a commodity market with merchant projects has gradually withered away.

The irony is that the foundation of the British model has been undermined just when the Commission has finally got towards getting the IEM implemented in most member states.

4. Capacity markets

Whilst Europe has concentrated on a commodity market model, and in particularly the IEM, two factors have undermined it, beyond the climate change policies. These are: the national security of supply requirements, and the coming of zero marginal cost generation; and the move away from energy as a commodity toward energy as capacity.

The case for a wholesale-only or energy-only electricity market has always been weak. The core theoretical model relies on assumptions that can never be met. Amongst these, perfect information abolishes the security of supply marginal problem. Agents are assumed to know demand. But they do not, and given that the costs of excess supply versus excess demand are asymmetric, and given that security of supply is a system and not a marginal feature of all electricity markets, there will always be a need to provide the pubic good of security through an excess capacity margin. Worse, it is not profit maximizing to deliberately create this margin, since it forces the average price below the margin necessary to reward capital investments. A rational investor will always prefer to allow the wholesale price to peak and ration off demand.

This system public good requires excess capacity, and hence a mechanism for ensuring it is provided. In addition, and even if the information and incentive problems are addressed, the political reactions to price spikes are likely to undermine the peaking wholesale price option. The reason why a number of countries got away with ignoring the security of supply capacity market problem in the 1980s and 1990s was because of deindustrialization and the legacy of the capacity built in the 1970s and early1980s for an industrial base that ceased to grow as anticipated. By accident, many European countries ended up with significant capacity margins. This was true especially in Britain, but also as France's nuclear build programme progresses.

Separate to the conceptual mistake, the underlying technological shift with both digitalization and new electricity generation technologies has begun to undermine wholesale markets. Increasing amounts of zero marginal cost generation has driven wholesale prices down, and in Germany there have been periods of zero or negative prices. This cannibalization of the generation market has already undermined investment in conventional plant, and reinforced the need to provide capacity contracts to both renewables and fossil fuel plants. This is especially true in Germany, which will now need to incentivize investment in new gas power stations to replace coal, and for similar reasons in the UK.

Rolling forward towards 2050, zero marginal cost will dominate the electricity systems, with ever-smaller amounts of variable marginal cost peaking capacity. Some argue that this peaking plant will still set the price. However a moment's reflection tells us that the occasional gas peaking plant cannot set the price for all the rest of the generation fleet without political and economic detrimental impacts. What will eventually happen is that the reserve will probably go into an insurance-backed fixed priced contract world. It will be reserve capacity, not reserve energy that is provided.

The existence of a security of supply peaking requirement relies upon the absence of storage and a passive demand side. It is here that the other technological changes kick in as we move towards 2050. The electrification of transport brings batteries into the center of the markets, alongside a host of other storage options. Digitalization, with robots, 3D printing and AI brings great flexibility first to factories and then to houses. Robots can take their holidays at points of peak demand, not in August when the beaches beckon human workers.

5. Bringing it together with Equivalent Firm Power auctions and regional and national system operators

In the *Burn Out* and in the *Cost of Energy Review* I set out how to redesign electricity markets to meet the new technological contexts. There are two main elements: EFP auctions and system operators.

5.1. EFP auctions

In a fully zero marginal cost world there is no marginal price. Before then, as more and more intermittent zero marginal cost generation is added to the system, the economic value shifts towards capacity and away from the wholesale market.

The required level of capacity needs to be decided at the system level, and the best way of meeting the requirement is to auction it. In the British example this is already achieved through a firm power (FP) capacity market, set after the renewables (paid for outside the capacity market by FiTs and CfDs) have been de-rated by the System Operator.

The EFP auction is the route to including the renewable into the capacity market, and in the process normalizing them, allowing for a gradual eliminating of subsidies. Renewable lobbyists regularly claim that renewables are cheaper and grid competitive, and hence that this normalization is taking place in any event and subsidies can be phased out.

The EFP auction explicitly incorporates the intermittency by de-rating the intermittent technologies. It does this on the basis of their contribution to the portfolio of generating plants as a whole.

The EPF auctions explicitly incentivize the intermittent generators to find bilateral and market contracts to mitigate their intermittency – from storage, the demand side and back up generation. The costs of the intermittency are placed with those who cause it.

To the extent that gas is required, as for example now in Germany, the EFP provides a way of addressing the falling away of the wholesale price. The twist to the EFP comes from the carbon constraints. Optimally these can be address through carbon pricing. If for political reasons, there is an unwillingness to face the ultimate polluters – the consumers and business customers – with the cost of the pollution their energy use causes, then there is a case for an adjusted EFP auction or even a two-stage auction, with the first round unconstrained, and then a second round after the constraint has been applied.

5.2. System operators

To make the EFP auctions work, there needs to be some institution to set the required capacity for auction, and to run the auctions. This is the role of the System Operator.

As electricity systems decentralize, there is a role not only for a national system operator (or even a European SO) but also for regional or local SOs at the distribution level (RSOs).

The RSO has the options of meeting additional demand from storage, generation, network enhancement or the demand side. The RSO auctions the regional capacity requirements to meet security of supply. Since this can come from any or all of these sources, the distinction between distribution, supply and generation breaks down. A single unified license can replace the three currently utilized. This is a major reform away for the design of the IEM, which focuses on disaggregating and unbundling distribution. In the next stage of the German transition away from both nuclear and coal, system planning and stabilization will be at an even greater premium.

6. Conclusions

The electricity market in Europe is going through a period of profound change, driven by new technologies including digitalization, the carbon constraint and the electrification of transport. It is doing so in the context of the growing Russian threat to Ukraine and to Europe more generally.This new world is characterized as a result by more and more zero marginal cost generation and by smart information technologies. These in turn not only open up all sorts of new opportunities, but also change fundamentally the underlying cost structures of the industry.

As a result of these fundamental changes, the existing corporate and instructional structures are no longer fit for purpose. A fundamental industrial restructuring is now well underway, with the demise of the great vertically integrated utilities of the twentieth century already largely completed. What have not yet changed are the policy and regulatory frameworks and

institutions. These now need to be urgently addressed, with capacity markets and auctions, and the development of system operators. As the wholesale markets gradually wither away, they should be replaced by EFP auctions, conducted by national and regional system operators. This new framework is the best way not only to optimize the existing systems, but also to fully incentives the new technologies and their applications to the demand side, storage and new renewable technologies. In the process it will make the development and integration of electric transport faster and cheaper. It will also help manage the transitions for coal.

As Europe moves towards greater electrification, it can gradually wean itself off Russian gas. In the meantime encouraging greater security of electricity supply through greater attention to capacity and capacity markets will lit the immediate Russian threats, including to Ukraine.

Chapter 2
Towards a world without fossil fuels: Vision, challenges, and opportunities for action in Europe

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In the Paris agreement, the European Union (EU) has pledged to reduce its greenhouse gas (GHG) emissions by 40% until 2030 relative to the level of 1990. Furthermore, by 2050, the EU intends to have achieved a low carbon society with at most 5-20% of the 1990 emissions remaining per year. Whether and how the EU will be able to deliver on these ambitions is, however, a matter of speculation.

Geopolitical aspects rank highly among the challenges for achieving EU emission targets. The EU would find it much harder to follow through on an ambitious internal climate agenda, if significant players in the rest of the world did not reciprocate the effort – the more so if those players even were to choose an adversarial agenda towards the EU. The European pledge is one of the most ambitious ones among all Nationally Determined Contributions (NDCs), and there is great uncertainty whether the pledge-and-review approach adopted in Paris will generally be able to encourage similar efforts from other important parties to the agreement.

Furthermore, the measures that implement the European ambition have to be acceptable to the electorates throughout the member states. Thus, unless emission reduction at all cost became voters' overriding priority, the EU and member states would still need to deliver sustained economic growth and to finance ample welfare schemes. Moreover, drastically reducing CO_2 will involve higher (explicit or implicit) taxes on energy consumption in order to refinance investment as well as to counteract the rebound effect. Increased energy prices have regressive distributional effects. Therefore, narrowly pursuing a climate agenda without

[16] Upon request by France Stratégie. I thank Dominique Auverlot, Dieter Helm, Max Gierkink, Fabien Roques, Johannes Wagner and the participants in a workshop held in Paris on 10th December 2018 for many valuable comments.

a redistribution scheme would most likely exacerbate the tensions within European societies. The "gilets jaunes" movement in France gives a glimpse on the potential scale of the social conflict arising from a socially unmitigated climate policy. In order to maintain acceptance for climate action within the EU, policymakers need to manage the industrial and the distributional dimension of such a policy, too.

Therefore, a successful and sustainable energy policy needs to take an integral approach, considering social, ecological and economic aspects at the same time, and at the global, European, and national levels, respectively. It should not only encompass the technological dimensions of potential future developments consistent with the climate targets and the regulatory measures to enforce such developments. In addition, it must also address the distributional and geopolitical challenges.

Reflecting on a set of questions posed by France Stratégie, this essay discusses three perspectives on a coherent European energy strategy. Firstly, we describe techno-economic conditions consistent with a timely implementation of measures in order to achieve ambitious emission targets across the various energy sectors. Thus, referring to the example of Germany, we present a hypothetical energy future based on current knowledge of technologies, current expectations regarding their future development as well as on the assumption that European societies will accept the consequences of such a strict decarbonisation agenda. Secondly, we consider the European approach to addressing the climate challenge, both externally, especially towards the UNFCCC negotiations, and internally, towards regulating energy-related emissions within the EU. The current approach delivers investment and behavioural patterns, which are inconsistent with the climate targets. Hence, we reflect on potential changes to the regulatory paradigms, which could serve to reduce that gap. In doing so, we stress the importance of a strategic shift to imposing an effective cost on carbon. Thirdly, and in line with France Stratégie's guiding questions, the essay considers the electricity sector in more detail. Focus is on appropriate measures to allow for short-term flexibility and long-term investment, critically reviewing the current EU liberalisation paradigm in the process. The essay concludes with a brief summary of the main findings, and a discussion of the implications for the respective roles of the EU and member states in achieving a successful energy transition.

1. The future at 2050 of the energy system – Case-study for Germany

Together with the Institute of Energy Economics at the University of Cologne (EWI) and further partners, the German Energy Agency (dena) has recently presented two potential pathways to a low carbon German energy system[17]. One pathway (EL) gives a priority to direct electrification in all the energy sectors, while the other one (TM) takes a more neutral stance on the choice of final energy carriers. The study indicates that energy systems with 80 percent GHG reduction relative to 1990 (EL80,TM80) differ substantially from energy systems that achieve 95 percent (EL95, TM95), in particular regarding the fuel mix and the composition of the capital stock. The study also shows the value of a technology-neutral approach to the transformation. In particular, it finds that a forced and extensive

[17] Dena, 2018, dena Leitstudie - Integrierte Energiewende, Berlin.

electrification of final energy sectors would lead to significant increases in the cost of the transition: according to the scenario analysis, Germany could save more than 140 billion Euros in cumulated cost by 2030, and almost 600 billion Euros by 2050 with a more technology-neutral approach to the final energy mix.

It is important to note that the dena-study, taking into account current political conditions in Germany, excludes both nuclear and CCS from the set of feasible technologies[18]. Thus, there are only three potential sources of nominally 'zero carbon' final energy[19]: electricity, biomass (or some derivative, especially biogas), and hydrogen (or some derivative), and Germany can produce these final energy carriers only from renewable energy sources (RES). Additionally, import of such energy carries is an additional option. Beyond the 'zero carbon' energy carriers, natural gas would be employed up to the allowed level of emissions (80%-scenarios) on top of the emissions from processes and agriculture (livestock), while coal and oil only remain in use for certain, specific applications. In the 95%-scenarios, no energy-related emissions remain. In the following, we will summarise and compare the main scenario results for 2050[20].

1.1. Electricity

For the electricity part of the system, all scenarios show electricity demand increasing from 567 TWhel (2015) to 809/837 TWhel (TM80/TM95) or even to 1,150/1,156 TWhel (EL80/EL95) by 2050. Covering those absolute demand levels, the scenarios show a similar general structure but different relative shares of the technologies. RES are expanded to their full realistic potential (Wind onshore), or close to that (Wind offshore, Photovoltaics). Thus, the scenarios project them to deliver some 740-850 TWhel by 2050 (2015: 179 TWhel). This translates into relative shares of 91% of RES in the TM-scenarios, but only 76/87% in the EL-scenarios, because further increases in RES production are limited and can therefore only partially provide for the increased electricity demand in these settings. The remaining electric energy is generated from dispatchable power plants, most of which run on gas. Gas, here, can be either natural gas or carbon-neutral gas from either biomass or RES electricity (hydrogen, or derivatives). The high electricity demand in combination with the less stringent emission cap in EL80 leaves 179 TWhel from natural gas in the system. In all the other scenarios, the electricity sector does no longer use conventional gas, since the remaining GHG emission budget directly serves the final energy sectors. Biogas and synthetic gas, by

[18] E.g., Fürsch *et al.* (2013, Decarbonizing Europe's power sector by 2050 - Analyzing the economic implications of alternative decarbonization pathways, Energy Economics, 40, 622-636) suggest that allowing nuclear or CCS into the mix may significantly reduce total cost in the electricity system. However, public acceptance poses fundamental challenges for major investments into both of these technologies, and the corresponding debate transcends purely economic aspects. Given the current state of public opinion across the EU, it seems difficult at present to envisage investments into either nuclear or CCS at the scale necessary to imply an energy system fundamentally different from the ones described in the dena Leitstudie.

[19] In using the term ‚zero carbon', this paper follows the convention to disregard upstream emissions. Such upstream emissions are non-negligible for some of the relevant technologies, e.g. for the production and transport of imported photovoltaic modules or batteries.

[20] For a more detailed explanation of the short-term implications of the scenarios until 2030, cf. Bettzüge and Hennes, 2019, Deutsche Klimaziele 2030 – zur Größe der Herausforderungen, Wirtschaftsdienst, 99 (3), 177-180.

contrast, are important for electricity generation in all scenarios, ranging from approximately 70 TWhel (EL80, TM80, TM95) up to 123 TWhel (EL95). Effectively, thus, the juxtaposition of EL and TM shows that there will be a trade-off with respect to the use of the (remaining) fossil fuels and synthetic/biogenous fuels: they can generate electricity, increasing the electric share in final energy consumption, or they can directly serve as final energy carriers. In essence, economic parameters should determine this choice. The cost analysis based on the dena-scenarios indicates that there seems to be a limit to the economic efficiency of electrification, which is far below the share of electricity in final energy consumption adopted in EL80/95.

Modelled peak load increases, especially in the EL-scenarios, from 84 GW (2015) to 102/103 GW (TM 95/80) and to 160 GW (EL 80/95), respectively. In all scenarios, gas-fired capacity predominantly secures peak load situations, with more than 50% of secured capacity in TM 80/95, and even more than 65% in EL 80/95. Similarly, energy provision in a hypothetical two-week-cold spell in winter relies largely on gas, accounting for 52%/67% of the generation mix in such situations in 2050 (TM / EL). Moreover, electricity demand will increase in such meteorological conditions, from 22 TWhel (2015) to 29 TWhel (2050) in the TM-scenarios, but even doubling to 45 TWhel in the EL-scenarios, due to the much higher penetration of electric end-use appliances.

Consequently, utilisation of thermal power plants greatly diminishes. According to the dena-study, conventional power plants delivered 426 TWhel from 91 GW of capacity in 2015, yielding an average nominal utilisation factor of 53 percent. For 2050, the scenarios project conventional capacities of 67/68 GW (TM80, TM95) and 123/127 GW (EL80, EL95), the substantial difference again being driven by the more ambitious electrification of the end energy sectors in the EL-scenarios. These numbers imply much lower utilisation factors of 23% (EL95), or even as low as 11-12% (TM80, TM95, EL80), in the future.

In order to integrate the large volumes of distributed RES capacities as well as the additional electric applications in final energy, distributed as well, there is substantial need for grid investments in all the scenarios. Until 2050, the scenarios project an investment need of 80-110 billion Euros in the German transmission grid, an increase in the net-transfer-capacities with neighbouring EU countries from 28 GW (2020) to 51 GW (2050), as well as investment of between 150 billion (TM-scenarios) to 250 billion Euros (EL-scenarios) in the distribution grid. Again, strong electrification implies much higher capital expenditure than a more technology-neutral approach, relying on a broader mix of final energy carriers. Not conducting these grid expansions would lead to significant challenges for the RES-based energy strategy, as one might need to curtail wind and solar plants and/or electric end-use appliances[21].

A final word on the role of electricity storage (apart from hydrogen). The dena-scenarios project such storage capacity to increase from 6 GW (2015) to 15-18 GW (2050) in all the

[21] For the charging of electric vehicles, the dena-scenarios assume stochastic charging behaviour. There exists significant optimization potential from shifting to smart charging. However, many technical and regulatory challenges remain and currently are a very active field of research. For an overview, cf. e.g. Ketter *et al.* 2018. Information Systems for a Sustainable Smart Electricity Grid: Emerging Challenges and Opportunities. In ACM Transactions on Management Information Systems, 9(3):10:1–10:22.

scenarios. Thus, dedicated electricity storage can contribute to secured capacity to some degree. However, given the low energy content of such storage options, their impact on the overall energy mix is limited. E.g., in the two-week cold spell mentioned above, dedicated storage would deliver less than 1 TWh to the system. Hence, batteries and the like will be important ingredients to a future electricity system in terms of providing for short-term flexibility, especially in peak-load situations. But dispatchable plants running on high energy density energy carriers such as natural gas, biogas, or hydrogen, will still provide for the bulk of seasonal security of supply. Moreover, since seasonal security of supply requires high amounts of installed capacity of dispatchable plants, these plants might provide short-term flexibility, as well, further limiting the scope for dedicated electricity storage[22].

1.2. Final energy consumption

Electricity currently makes up 20% of the 2,591 TWh of German final energy consumption[23]. According to the detailed modelling of final energy in the sectors buildings, industry, and transport, the role of electricity will have to increase significantly in all scenarios meeting the 80% or even 95% GHG reduction target for 2050. In particular, the EL-scenarios project the share of electricity to increase to 60-63% by 2050, while the more technology-neutral TM-scenarios see an increase of this share up to 34-35%. In parallel, total final energy consumption decreases steadily in the scenarios, down to 1,474 – 1,674 TWhel. Electrification, and the associated gains in the technical degree of efficiency in end-use applications, is one major reason for this projected decline in final energy consumption. Further increases in energy efficiency derive from other improvements in the capital stock, e.g. the quality of the insulation of buildings or the adoption of new industrial processes.

Importantly, even in scenarios assuming a strong push for rapid electrification, non-electricity final energy carriers retain a substantial share of the energy supply, and even more so, if society were to refrain from the additional cost associated with enforced electrification. The use of gas and fuels with high energy density is obviously required throughout all the scenarios, independent of the reduction target. The lower the remaining emissions, the higher the share of 'green fuels' relative to fossil fuels. The projected energy future therefore is clearly not all-electric on the level of final energy consumption. For example, in the TM scenarios, total gas consumption will increase from 770 TWh in 2015 to 804 TWh by 2030. From then on, the combined primary energy total of natural gas and (imports of) carbon-neutral fuels reduces only slightly to 761 TWh by 2050 (TM80), predominantly (609 TWh) in the form of natural gas, or increases even further to 885 TWh (TM95), with carbon-neutral fuels imports (744 TWh) allowing for the additional reduction of GHG emissions in Germany. Even in the electrification scenarios, the combined primary energy total of gas and carbon-neutral fuels will remain significant at 567/445 TWh (EL80/95) in 2050.

Origination of carbon-neutral fuels, thus, will become a main enabler for a low-carbon, industrial society in Germany, with limited national RES-potential, and nuclear and CCS

[22] For an extended discussion, cf. EASAC, 2017, *Valuing dedicated storage in electricity grids*, Brussels.

[23] AGEB, 2018, Auswertungstabellen zur Energiebilanz Deutschland 1990-2017, Berlin.

technologies renounced[24]. Most of these imports will have to come from outside the EU, for example from Russia, the Ukraine, Norway, or North Africa. Stricter electrification can reduce such import needs, but only up to a point: EL80 only requires 25 TWh of such PtX-imports, because the remaining natural gas largely suffices to balance the electricity system. However, sharpening the climate target to EL95 implies a drastic increase in the imports of carbon-neutral fuels to 396 TWh.

Overall, the bottom-up, high-resolution scenario analysis of both the electricity and the final energy sectors argues that gas in all its future forms - with its enormous storage potential at high-energy density- provides for security of supply, especially in the electricity sector. Hence, in a certain sense, one might consider the gas infrastructure the backbone of the energy transition. Appropriately safeguarding therelevant parts of the capital stock and the infrastructure supporting such gases and fuels, therefore, will most likely form an essential part of an economically efficient, and thus societally effective, energy transition.

1.3. Implicit assumptions

The dena-scenarios, as well as other comparable scenarios, are neither forecasts nor blueprints for a centralised 'master-plan'. They describe hypothetical developments, identifying conditions and consequences at some level of detail. In doing so, these scenarios point out that the European and national GHG targets seem to be in principle consistent with a (moderate) increase in economic activity until 2050[25]. However, even when taking into account the purely techno-economic level reflected in the scenarios and their inherent optimistic bias, one recognizes the enormous challenges for actually implementing pathways like the ones described.

To start with, the scenarios quantify substantial investment needs throughout the various energy sectors. For example, private households would have to increase their investments into refurbishing buildings and heating systems by 8 billion Euros, or 220 Euros per household, per year compared to the reference scenario[26]. Similarly, the transportation and industrial sector would also require additional investments into more capital-intensive technologies, forced depreciations, and new infrastructure. For the energy sector, the dena-study identifies an additional annual burden in order of at least 10 billion Euros compared to the reference scenario, not including decreased producer rents. These cost estimates, moreover, presume sufficient expansion of the required grids. Failures, or delays, in grid expansion would impose additional cost, as electricity production from renewable energy sources might need curtailing,

[24] The scenarios assume that technology development will drive down sourcing cost for hydrogen outside the EU to 74 EUR/MWhth in 2050, excluding transport cost. There is a sensitivity testing for the impact of higher cost of electrolysis, both inside and outside the EU, leading to hydrogen sourcing cost from outside the EU of 126 EUR/MWhth in 2050. In this sensitivity, total PtX volumes remain largely unchanged in TM95/EL95, but Germany would import them from within the EU rather than from the outside. Total cost would increase in both TM95 and EL95, but the overall cost difference between the two would reduce

[25] The dena-scenarios assume real GDP to grow at 1.2% p.a. in the decade 2020-29, and at 0.9% p.a. thereafter.

[26] The reference scenario already includes significant efforts to decarbonize the energy system, which are, however, insufficient to meet the climate targets by 2050. Efforts modelled in the reference scenario surpass the achievements realized in the past two decades. Thus, the additional burden identified in the target scenarios underestimate the economic and political challenge for switching from status-quo policies to policies consistent with the target scenarios. This challenge obviously over time as long as investment levels remain below the projected trajectories of the target scenarios, as more change has to be effectuated in a shorter period of time in order to meet the targets set for the specific deadline of 2050.

or local storage at additional expense. On a purely techno-economic level, these assumptions require that the economy can physically deliver such changes, shifting resources from other parts of the economy into the energy sectors, and still deliver the moderate growth rates assumed. Scenarios typically are too optimistic when it comes to ramping up investment rates, e.g. in electricity grids or charging infrastructures, in building refurbishing or in adoption rates for vehicles with alternative drivetrains.

On the econo-political level, moreover, the scenarios imply a hitherto unprecedented decoupling of GDP and final energy consumption at a rate of far above 2% per year, year on year, from 2015 until 2050. With hindsight, long-term pathways regularly tend to overestimate the opportunities from decoupling GDP from energy demand ("energy efficiency"), for example by ignoring a potential rebound effect[27]. Thus, the scenarios tacitly assume that the regulatory framework supports both the transition in the capital stock and the projected reduction in energy demand preventing any offsetting rebound effects. Furthermore, as legislation depends on a corresponding political environment, the scenarios also suppose that European societies will accept such regulation. Barring fundamental changes in voters' attitudes, a successful energy transition therefore also requires a dedicated set of measures to counter potential resistance to the energy transition on distributional grounds as well as global cooperation at a fundamentally different level than today – otherwise European stringency might lose credibility with the European public. In addition, the transition would have to accelerate significantly. In fact, for Germany, the annual reduction rates for energy-related GHG emissions would have to quadruple relative to the past two decades just in order to achieve the 2030 targets, and it would have to do so with immediate effect[28]. Thus, the ambition level of current political targets would have to be one of radicalism rather than gradualism.

Hence, while the dena-scenarios indicate a technologically viable pathway to the targets set for 2050 – with many optimistic assumptions, and for a trajectory of rather moderate economic growth – the economic and political dimensions of the transformation described in the scenarios are enormous and call for special attention on behalf of policy-makers. Important questions arise which will guide the following discussion of regulatory approaches to the energy transition: How to increase and speed up sustainable investment? How to increase energy prices alongside the improvements in the capital stock (in order to avoid potential rebound effects)? How to deal with the regressive effects of such energy price increases? How to maintain economic productivity throughout the economy, while not overburdening the carrying capacity of private energy consumers and the state budget? In the European context, how to harmonize the finely tuned interventions into markets and income distributions – which will most likely be the domain of member states' governments – with the EU internal energy markets and the EU regulation on illicit state-aid? From where to import to import substantial volumes of carbon-neutral 'green gas', and at what cost? Finally, in the global perspective, how does the EU contribute to effective global emission reductions, and how can the energy transition in Europe flexibly align with the efforts in the rest of the world?

[27] E.g. Bettzüge (2018, Zuviel nationale Zuversicht – Lehren aus der Zielverfehlung 2020, ifo Schnelldienst 18 (1), 15-18) finds *ex-ante* overestimation of improvements in the macroeconomic energy efficiency to be one of the major reasons for the discrepancy between the scenarios produced on behalf of the government in 2007, projecting an ambitious reduction target for 2020, and the actual emissions trajectory.

[28] Without a revision of targets, further delays will only increase the gradient for later action.

2. Europe within the global effort to curb carbon emissions

Energy conversion from burning oil, coal, or gas induces energy-related emissions of carbon dioxide (CO_2). There is a negative environmental externality from such emissions because of their impact on climate change. The textbook suggestion for internalising this externality are so-called 'carbon prices', either from imposing a tax on fossil fuels (or the corresponding emissions), or a cap-and-trade scheme[29]. A cap-and-trade scheme can guarantee that emission volumes do not surpass a given threshold, but the price of carbon is endogenous. Taxes, on the other hand, leave the CO_2-volumes endogenous, but exogenously fix the 'price'. A tax-based system, theoretically, can replicate the emission reduction achieved by the cap-and-trade-scheme, if policymakers implement the corresponding pathway for the carbon tax.

Generally, both taxes and cap-and-trade-schemes are statically cost-efficient, achieving the respective emission reductions at the lowest possible cost. With complete information for the policymaker, the instruments are effectively equivalent, while incomplete information can favour one over the over depending on the shapes of the cost and damage functions as well as on further model specifications[30].

Note that the damage function of CO_2 only exists at the global level. Therefore, such analysis is meaningful only with respect to the global choice of a price-based versus a quantity-based instrument. In this context, the predictions made by climate scientists that global damage functions from increased temperature levels might become very steep beyond some critical level ('tipping points') suggest that the volume-based orientation of the Paris agreement with respect to total emissions (temperature increases directly related to corresponding carbon budgets) might be reasonable. However, it does not at all follow that states should coordinate with volume commitments as do many of the NDC's in the Paris agreement, including the EU's. For this choice, the shape of (global!) damage functions is irrelevant. Rather, one should choose the instrument which best overcomes the coordination problem between 200-odd sovereign nation states that all have an incentive to freeride on other countries' efforts. Common commitment and reciprocity are key for any successful agreement on the global level. Carbon pricing (in the wide sense, including carbon taxes) seems to be the most promising anchor for such common commitment, also allowing for relatively simple acts of reciprocity, especially via adapting the carbon price according to the effort of other parties, or by applying bordertax-adjustments[31].

The Paris agreement, based on Nationally Determined Contributions, does not include neither common commitment nor reciprocity between the parties. Theoretical, experimental and empirical evidence suggest that an agreement based only on unilateral pledges cannot overcome the coordination problem, and that such pledges will gradually erode. In fact, the

[29] Note that, rather confusingly, it has become common practice to subsume both taxes on CO_2 and CO_2-certificate prices under the term 'carbon pricing'. However, only a cap-and-trade scheme generates prices on CO_2 emissions in the literal sense of the word. Taxes are not determined on markets, unlike prices; rather they come on top of market prices in order to distort them in the environmentally desired way.

[30] Cf. the seminal article by Weitzman (1974, Prices vs. Quantities, *Review of Economic Studies* 41 (4), 477-491) and the subsequent theoretical literature.

[31] Cf. e.g. Cramton *et al.* (eds.), 2017, Global Carbon Pricing, MIT Press.

erosion of the Paris agreement might already have started with key signatory countries openly withdrawing from the agreement, or substantially failing to meet their individual targets. In any case, four years after the Paris agreement, global emissions continue to increase at more than 2% per year. Thus, at least so far, it does not yet deliver on the promise made in its article 4 "to reach global peaking of greenhouse gas emissions as soon as possible".

2.1. European approach to global climate negotiations

From the perspective of game theory, the unilateral mitigation strategy adopted by the EU, which sets itself absolute volume targets for specific years in the future, might not be particularly helpful for facilitating successful cooperation on the global level. Without reciprocity, it invites other countries to freeride on the EU's efforts, exploiting Europe's climate action to their own benefit. The widely held assumption in Europe that such unilateral front-runner behaviour will set a moral example that the rest of the world will then follow finds little backing from either theory, experimental evidence, or historical precedent. In addition, global projections of energy-related CO_2 emissions point to a steadily decreasing EU share (2005:15%; 2016: 10%), so the direct impact of the EU's efforts on climate change becomes more and more marginal.

What is more, the unilateral approach appears to be fragile with respect to its implementation at home. Already for 2020, key member states such as Germany struggle to meet their ambitious climate objectives. The more industries and citizens in the EU have to adapt their capital stock and their lifestyles due to ambitious climate action, and the more such radical mitigation policy negatively affects economic growth, the more the electorate might be inclined to question the sanity of wide discrepancies in climate action between Europe and the rest of the world. Although compensations of carbon leakage for certain industries counteract such global imbalances in principle, there are limits to their applicability. In particular, they create additional socio-political challenges by redistributing mitigation burdens to other industries and households. Therefore, it seems unlikely that EU policymakers would be able to stick to the strict volume targets they set out, if the world at large did not settle on a cooperative equilibrium.

European climate policy, thus, needs to start from the global perspective, aligning internal measures that mitigate emissions, with external negotiations, that serve to facilitate global cooperation. Without a move towards common commitments – rather than individual pledges – and reciprocity, European climate policy will likely put significant burdens on European companies and citizens to little avail for the global fight against climate change. In turn, this discrepancy between ends and means, potentially widening with ever more strict climate action at home and continued increases in emissions – and corresponding wealth - elsewhere could spur conflict in our societies. Thus, managing the energy transition – in particular, its gradient of change – via unilateral volume-commitments for fixed dates in the future looks like a questionable strategy both towards the external world in the UNFCCC, and towards negotiating the degree and scope of interventions into the energy system with the European electorate. Using targets for carbon prices, instead of emission volumes, as the guiding principle seems to have many advantages in both policy dimensions.

European climate policy therefore should consider turning from the current volume-based approach to a carbon price-based approach in the renewed NDC. For this move, an important starting point would be transparency about effective, average carbon prices within EU member states. Such calculation would include the ETS-certificate price, all taxes on fossil fuels, as well as the relevant subsidies and levies[32]. Moreover, given transparency about such carbon prices in Europe and across the world, flexible internal taxation mechanisms – dependent, among others, on effective carbon prices in other jurisdictions – as well as corresponding border-tax-adjustments could then implement reciprocity in a meaningful way. Note that offering reciprocity in such a way does not need 'a coalition of the willing' to start with; rather, it automatically creates an incentive for the EU's main trading partners to reciprocate themselves, thereby facilitating a move to a cooperative solution.

2.2. Carbon prices in the EU

Currently, the EU uses a dual approach when it comes to 'putting a price' on energy-related carbon emissions. On the one hand, the EU applies a cap-and-trade scheme, the ETS, for regulating emissions in certain sectors of the economy, in particular, for large-scale generation of electricity. The ETS ensures the cap on the integral of targeted maximal emissions. In a way, therefore, the ETS acts as an automatic backstop for a potential rebound effect in this sector. On the other hand, the EU leaves it to the member states to tax final energy use, including electricity.

For example, in Germany, the state applies taxes to various final energy carriers. Taxes are nominal, and, for fossil fuels, expressed in cents per litre or volume. As there is a direct equivalence of litres of fuel, or volume of gas, with the CO_2 emitted upon their use, energy taxes are effectively also taxes in Euros per ton of CO_2. Independently of maybe different justifications given for introducing those taxes in the first place, they provide incentives that are equivalent with carbon taxes in such orders of magnitude. Interestingly, nominal energy taxes have not increased in Germany since 2003, implying a substantial decrease in real terms.

There is a marked difference between the tax levels on various fuels. For example, heat oil tax is equivalent to around 21 EUR per ton of CO_2 emitted, while natural gas (for heat use) carries a tax of 28 EUR per ton. Even more striking is the contrast to the transportation sector: The German diesel tax amounts to 180 EUR per ton, and the gasoline tax almost 300 EUR per ton. The different tax levels for heat and transportation reflect the fact, that, in the absence of effective (ubiquitous) tolling mechanisms, fuel taxes are the nearest substitute for pay-for-use-pricing of road use, also internalising other negative externalities such as noise and congestion. Furthermore, heat and transportation services look very different from the perspective of taxpayers and voters: Especially for households with lower incomes, the tax base for heat fuels typically is significantly larger than for transport fuels. Moreover, tenants have no control over the choice of heating system in their homes. In addition, lower income household might lack the funds to invest into refurbishment. Thus, just increasing the level of heat taxation might induce such households to nothing else than a reduction of the average

[32] Cf. MacKay *et al.* (2015, Price carbon – I will if you will, *Nature*, 526, 315–316).

room temperature which, in turn, could cause public health issues. In transportation, in contrast, there is a wider range of substitution options, ranging from revisions of driving patterns (e.g. shared rides), increased use of public transport or other modes, more eco-conscious driving behaviour, to the adoption of smaller or more efficient vehicles. Replacement periods generally are much shorter in transportation than in heating, which further explains why, at least for the German case, the electorate is willing to accept much higher tax rates (on essentially the same fuels) in this sector.

For electricity, the situation is even more complex. On top of the ETS price, indirectly affecting the use of electricity as a final energy carrier, there is an electricity tax of 20.50 EUR per MWh. Applying an average emission factor of 0.55 tons of CO_2 per MWh for the German electricity sector, this translates to an implicit CO_2 tax of 37.27 EUR per ton. Moreover, electrical energy also carries an entire set of additional burdens, such as e.g. kWh-based grid fees and levies, especially for refinancing the RES subsidy scheme. In total, the effective incentive for CO_2-reduction with respect to the use of electric energy amounts to more than 300 EUR per ton (for a typical household). Thus, in CO_2 terms, and on the household level, electricity effectively is the most heavily taxed final energy carrier in Germany. *Ceteris paribus*, a future reduction of the emission factor (due to the ETS, the continued expansion of RES, and a managed coal decline) would exacerbate this disparity.

Because of the many trade-offs involved, harmonising the effective CO_2-price across energy carriers is an important ingredient to a successful energy transition. A single carbon price (or tax) is the gold standard for CO_2 mitigation in the final energy sector. It should replace all existing energy taxes. Tax levels should be close to existing levels to begin with, but the state should commit to increasing tax pathways in order to encourage anticipating investments. Current heterogeneity of tax levels calls for an appropriate transition period before full standardisation of tax levels. As discussed, transportation plays a special role here, so initially there needs to be an additional 'road-use energy tax' on energy used for driving individual vehicles. Note that this creates an administrative challenge in the case of electricity, since charging batteries is possible everywhere in the grid[33]. Longer term, there are options to replace the tax-top-up in transport, i.e. the 'road-use energy tax', with other incentives. In particular, toll systems could take on an increasing role, maybe even time-variant to improve upon traffic congestion. Replacing fuel tax-top-ups with such systems might also alleviate some of the social concerns expressed with further tax increases in the transportation sector. However, such tax reform in transportation is yet another big, and separate, challenge for policymakers.

For electricity, the need for tax reform is highest, since electrification of final energy will be an essential element of the energy transition, and the starting point is most confused. As electricity is already subject to the ETS, there is actually no reason, or benefit, from adding explicit and implicit taxes on the final use of electric energy (except in road transportation,

[33] The easiest way to implement higher taxes on electricity for transportation compared to other uses would probably involve specific technical standards for charging the car, preventing the use of regular plugs/sockets and allowing for the specific metering of charging (and discharging!) of batteries in vehicles. Such special controls will presumably be necessary anyway in order to allow for smart charging of plug-in EVs, including their use as virtual power plants in the electricity system.

see above). Member states, thus, should abolish them. At the same time, a revision of fixed grid fees needs to make electric load, storage, heat, and supply carry the appropriate burden of the induced capacity cost.

In parallel to committing on the principle of carbon taxation, and cleaning up the complex array of energy taxation, policies need to address the distributional implications of increasing energy taxes and prices. Such concept for redistribution must be an integral part of any national mitigation policy. Important elements include – ideally technology-neutral - support schemes for achieving the transition to a more efficient capital stock, especially for lower income households, using the additional proceeds for reducing other distorting taxes ('double dividend'), or outright tax rebates, for example for heavy commuters. Moreover, the state can facilitate the adoption of ever-increasing energy taxes by appropriate urban planning and an upgrade to public transport. Sweden and Switzerland provide interesting case studies how to design CO_2 tax systems with up-front announcements about their pathways, and how to complement them with distributional measures.

2.3. ETS vs. carbon taxes

In order to create and maintain a level playing field between electricity and fossil final energy carriers, the respective levels of the carbon prices should be identical. As long as the ETS exists, there are only two ways to make this happen: Either the ETS expands to cover all sectors, or member states have to peg final energy tax levels somehow to the ETS certificate price. Alternatively, the ETS could give way to a CO_2-tax that applies uniformly to all carbon emitting sectors in the economy, thus abolishing the rather arbitrary divide between ETS- and Non-ETS-sectors. Since the effective pegging of tax rates to the ETS will prove to be difficult in practice, given the significant volatility of the ETS certificate prices, the crucial choice seems to be between regulating the volume of CO_2-emissions in Europe with an extended ETS, and regulating the price of such emissions with a uniform carbon tax.

As discussed above, the (global) damage cost is irrelevant at the European level. From the perspective of global emissions, and thus, climate change, there is not much material difference whether the EU exactly achieves the volume targets in a given year, or over- or underachieves them. On the European level, the main economic difference between the volume-based and the tax-based approach consists in the way the state can shape the expectations of market participants, especially investors, with respect to the development of the carbon price. With a tax, policymakers can influence these expectations directly, by establishing a credible announcement on pathways for this tax, ideally with a visibility of at least several years. Pegging tax rises to inflation or the achievement of certain objectives, such as in the Swiss model, might add flexibility while maintaining the general approach of up-front commitment by the state[34]. In a transition period, announced tax pathways could also reflect the relative levels of existing energy taxes across final energy carriers.

With the ETS, policymakers lead through the announcements regarding the volume of tradeable permits, while the price of these permits is endogenous. The ETS price over the lifetime of an investment with the ETS sectors, therefore, is risky and depends on a multitude

[34] Moreover, it adds flexibility for global climate negotiations. See above.

of uncertain market developments, such as, for the case of electricity, e.g. power demand, fuel price levels and spreads, as well as technology cost. Moreover, there is substantial political risk in the market[35]. The recent ETS reform[36] has contributed to a price increase of ETS certificates, but it has also confirmed that there is uncertainty concerning the future stability of the ETS rules. The EU has at no point firmly – and terminally - committed to the total number of certificates it will make available over the lifetime of the ETS instrument. Policymakers might choose to fiddle with the number of certificates made available to the market in the future again, either because they find prices are ‘too low’ or ‘too high’. There even is the risk of a total collapse of the system. In addition, the EU and, in particular, the member states reserve the right for additional interventions into the electricity sector, such as subsidies or forced phase-outs of certain technologies, as well as for national cancellation of certificates. Again, investors can hardly foresee these interventions as the EU and member states find it hard to firmly commit and then tie their hands. Moreover, the impact of such interventions on the ETS price is complex and hard to predict, even if investors could anticipate them correctly[37].

Overall, therefore, the range of potential future price trajectories for ETS-certificates is huge, making the ETS add to the long-run investment problem in the electricity market[38]. Hedging against this risk is difficult as there is insufficient liquidity in long-term futures on ETS-certificates. Therefore, in principle, tax pathways can generate more visibility to investors than a cap-and-trade scheme, and, for this reason, they seem better suited for unleashing the spur of investment activities required to implement the energy transition. Note in passing, that policymakers use to phrase their pledges in the form of targets defined for specific years (e.g. “minus 40% in 2030 relative to 2005”). This principle is also enshrined in the effort sharing agreement concerning the Non-ETS-sectors and the associated penalties. By contrast, the ETS, using multi-annual trading periods and allowing for banking, does not implement such point predictions. Extending the effort sharing-paradigm to the ETS sectors as well would therefore align more clearly with the committed political objectives, which further weakens the case made for the ETS instead of a tax-based approach.

At the outset, there was no particular economic argument for choosing the ETS over a tax-based system. Rather, the ETS emerged in the context of the creation of an internal market for electricity. A harmonized price (or tax) on CO_2 was an important ingredient of this attempt, removing one (potential) source of distortion. However, the EU was not able to set a harmonised tax because of the unanimity required in the Council. The ETS was the answer to that problem. In the current constitutional setting of the EU, barring material and rapid progress along the lines of the recent proposals of the EU commission on the extension of

[35] Cf. e.g. Salant, 2016, What ails the European Union’s emission trading system, *Journal of Environmental Economics and Management* 80, 6-19.

[36] For a formal analysis, cf. e.g. Bocklet et al., 2019, The Reformed EU ETS – Intertemporal Emission Trading with Restricted Banking, ewi Working Paper 04/19.

[37] E.g., the rules on MSR cancellation introduced in 2018 will most likely lead to an automatic cancellation for all additional measures only if these are effective prior to the first cancellation planned for 2023. Afterwards, one should expect only be minor such compensatory effects from the MSR. Cf. Hintermayer and Schmidt (2019, Assessing shocks and overlapping policies in the EU ETS – Can the reform live up to its promises?, ewi Working Paper forthcoming).

[38] Discussed in more detail in the next section.

qualified majority voting (QMV) 39,24 transitioning to a carbon tax would still imply a devolution of the responsibility to mitigate in the ETS sectors to the member states. The upside in visibility and simplicity of the tax-based approach must therefore overcome the downside resulting from

cross-border inefficiency created by the (further) distortions to the internal market on electricity, which would arise from heterogeneous tax rates. While probably not being able to agree on a fully harmonized tax path, the Council could strive at least for an agreement of minimum taxes throughout the EU40.25 Harmonising carbon tax rates in bi- or multilateral agreements, for example between France and Germany, or in the Pentalateral Forum, could further alleviate this downside.

At first glance, (national) carbon floor prices within the ETS, at the level of (national) carbon taxes, might appear to deliver the 'best of both worlds'. However, at closer inspection, the case becomes less clear. Carbon floor prices (and ceilings), of course, would add more visibility for investors, especially in the short-run. However, they distort the intertemporal efficiency of the ETS with banking. Overall, if one considers the economic upside from the increased short –term visibility to outweigh the losses from the distortion of the ETS, then why keep the ETS at all?

Moreover, keeping the ETS alongside national carbon taxes would only make sense if ETS prices surpassed national carbon taxes in certain member states and at certain times. Thus, the ETS would distort the level playing field between energy sectors on the member state level, hampering an efficient local energy transition. The continued use of the ETS would reduce visibility, as market participants would need to observe both the (national) pathway for the carbon floor price as well as hedge against a potentially even higher ETS price. The benefits of such added complexity, conversely, appear to be rather limited. The effort sharing agreements between member states do fix annual emission levels for milestone years (such as 2030). The overall quantity target for 2030 on the level of the EU, hence, could remain, enforced by penalties against the member states, analogously to the approach adopted in the Non-ETS-sectors. Being made explicitly accountable for mitigation across all sectors would then allow member states to develop a comprehensive national mitigation strategy including CO_2-taxes on fossil fuel use in the current ETS sectors, consistent with the taxes used in the Non-ETS-sectors, and adapted to any additional national measures. Against these potential benefits of such an approach, the ETS only adds the fixing of total emissions cumulated over the trading periods. Does this benefit – which does not carry much material advantage for the global climate effort, as explained above - really justify the added complexity, investor risk, and lack of accountability?

Given this background, carefully weighing the respective costs and benefits of both the ETS- and the effort-sharing-cum-tax-based approach might invite a fundamental revision of current EU policy approach to CO_2 mitigation. While harmonising the price (tax) paid for CO_2 was an

[39] EU Commission, 2019, Towards a more efficient and democratic decision-making in EU tax policy, COM (2019) 8 final.

[40] The approach allows for subsets of countries to harmonize their tax rates in bi- or multilateral agreements, e.g. between France and Germany, or within the Pentalateral Forum.

important motive for EU integration in the 1990's and 2000's, how important is this objective today compared to the objective of achieving a fast, effective and efficient energy transition in all the member states? – By adopting a plethora of national measures within the ETS sectors, the member states already seem to give their answers to this question.

2.4. Further regulatory measures

Regulating the price of carbon, via taxes or a cap-and-trade scheme, is an economically reasonable solution for internalising the climate effects of fossil fuels, because it allows market participants to adapt their behaviour and capital stock efficiently. In applying such a solution on the European or national levels, visibility is important in order to reduce investment risk, and pathways of taxes/prices should align with global common commitments by all parties to the UNFCCC.

Beyond the pricing of carbon, the economic perspective suggests an additional need for further regulatory action only under specific, narrow circumstances, e.g. for removing asymmetric information on behalf of end-consumers, or for leveraging effects of knowledge spillover[41]. In general, however, such specific interventions are prone to inefficiency due to incomplete information on behalf of the regulator, and they open the door to extensive lobbying efforts by the industries affected. There is, therefore, a significant risk of inefficient policy outcomes, which one always needs to weigh against the alleged benefits of the additional measure.

Note that measures targeted directly at the structure of the capital stock cannot substitute for increasing carbon prices. Either the measure increases the efficiency of the energy system; then, without increases in the price of fossil fuels, there is the risk of compensating rebound effects; or the measure actually decreases system efficiency, in which case energy prices will increase for this reason, and typically by more than with a corresponding increase in the carbon price.

Tax rates or carbon permit prices transparently show the hardship inflicted on the economy, but they could potentially have broad (distributional) repercussions, which policymakers typically find hard to anticipate (and, consequently, do not want to risk). Policymakers, thus, tend to favour direct interventions into the capital stock (e.g. RES subsidies, emission standards, coal phase-outs etc.) over increases in tax levels, maybe because the hardship inflicted is less transparent, and specific distributional countermeasures become much easier. For example, the ETS is not an encompassing upstream mechanism covering all sectors; rather, it has been restricted to certain industries, which allowed for targeted compensation mechanisms ('carbon leakage'). The German law for supporting electricity generation from RES provides another telling example[42]: RES-investors and RES-suppliers benefit from the subsidies given, while energy-intensive industry is largely exempt from the RES-levy, thus becomes a net beneficiary, too, due to the merit order effect from the

[41] Cf. e.g. Fischer and Newell, 2008, Environmental and technology policies for climate mitigation, *Journal of Environmental Economics and Management*, Volume 55 (2), 142-162.

[42] Cf. Bettzüge, 2014, Nationaler Hochmut oder cui bono? Ökonomische Betrachtungen zur deutschen ‚Energiewende', *Physik Journal* 5, 33-38.

increase in RES-capacities. For all other power consumers, electricity prices have significantly increased, but there has been scarce representation of their economic interests in parliament, let alone government[43].

Another interesting case study – with a similar structure of political collusion - are the propositions recently made by the so-called WSBK, i.e. the commission appointed by the German government to identify a roadmap towards an accelerated phase-out of German coal-fired capacities and lignite mines. From a mitigation perspective, implementing the proposed closure of coal-fired power plants would not change much with regard to the integral of CO_2 emissions under the ETS[44]. Even as an additional national measure, it is not cost-efficient since an appropriately chosen carbon floor price (or carbon tax) could reduce the same amount of (national) emissions at lower cost. At the same time, simulations indicate that closing down coal-fired power stations would lead to an overall increase in the wholesale electricity price[45]. Thus, it is not easy to find economic logic in the proposals made. Economically, the key advantage of the WSBK-plan might be the firm commitment by the state through a binding agreement with the main stakeholders. Note, however, how much simpler the state could arrive at such commitment by using announcements on tax pathways instead, which would, on top, be cost-efficient.

Nonetheless, the compromise adopted by the commission obviously carries significant political value by directly addressing the various distributional effects on producers and (some energy-intensive) consumers. In particular, in contrast to a floor price (or tax), the WBSK proposals can address lignite specifically which appears to be (politically) important because of the special situation of the mines; with a technology-neutral approach, given relative cost structures, hard coal would be first affected and the phase-out of lignite would turn out less gradual in nature. Moreover, public sentiment seems to see symbolic value in taking out coal-fired power stations independently of the actual effects on total emissions, partly for symbolic reasons, partly maybe because there is a perceived risk of a political lockin of this influential industry. Overall, therefore, policymakers seem to be willing to trade the economic inefficiency of such an intervention for a perceived political gain.

The EU emission standards for passenger vehicles might serve as a final example for the preference given to direct intervention into the capital stock. These standards, as many other such interventions, are showing an inefficient skew towards electrification[46]. Moreover, the

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[43] Cf. Olson, 1965, The Logic of Collective Action. Public Goods and the Theory of Groups, Cambridge, Harvard University Press.

[44] Unless the government would cancel ETS-certificates in corresponding amounts; but then it would be the cancellation rather than the phase-out of the power stations that served to reduce total emissions. Some limited effect might also result from increasing the number of certificates in the Market Stability Reserve that get cancelled; cf. footnote 22.

[45] Even though the carbon price itself – in this case, the price of ETS-certificates – would probably decrease slightly.

[46] The regulation does e.g. not account for the upstream emissions for manufacturing the batteries, while no corresponding border-tax-adjustments are in place. In addition, the alleged carbon neutrality of the fuel relies on the ETS-cap not adjusting for the increase in electricity demand from transportation. Effectively, thus, emissions originating from the transport would crowd out uses of fossil fuels in the current ETS-sectors – inducing exactly the trade-offs which the original separation of the ETS-sectors from the Non-ETS-sectors were supposed to avoid.

measure affects only (the fleet averages of) new cars, while there are no incentives regarding the existing car fleet or actual driving patterns. Even if this regulation improved average efficiency of vehicles sold, the net effect on emissions would be unclear unless corresponding tax increases were to shave off potential rebound effects (direct effects in road transportation, or indirectly in other sectors). Like standard-based instruments in general, these rules are also not particularly helpful in supporting dynamic decision-making by investors. Announcements concerning restrictions on certain technologies at a future point in time – such as the EU's communication on the development of standards, or the announced outright bans of internal combustion engine vehicles in several member states – are irrelevant for today's investments into new vehicles[47]. In order to influence those, it would be more important for investors to know about future regulation on the existing asset base. Announced tax increases seem to be a much more feasible anchor for shaping investors' expectations about the full lifetime cost of a new vehicle. Overall, therefore, the EU emission standards appear to be rather an instrument of industrial policy, favouring certain car manufacturers over others, than an instrument for effective, let alone efficient, emission reduction.

In summary, the general political preference for direct interventions into the capital stock over the use of an appropriate carbon price (or tax) needs scrutiny on a case-by-case basis. Policies should use standards or similar direct interventions, which are inherently inefficient, only with caution, with clear and measurable objectives in mind, and as neutrally as possible with respect to technology choice. Moreover, the cost of such measures to European consumers and producers need to become more transparent.

3. Regulating the electricity sector for the transition

The long-term pathways of a rapid and profound energy transition described so far are investment intensive in all sectors, including electricity. For the power sector, investment priorities comprise new power generation (from RES and from gas) and grid (both transmission and distribution). Moreover, there will be an increasing share of intermittent supply, and of new decentralized final energy applications with relatively high specific loads, especially electric vehicles (EVs), EV-charging stations and electric heat.

In such a future electricity system, bottlenecks in the grid - and, correspondingly, their efficient management – will take on increasing significance. Pressure on the grid will come from the supply side (RES) as well as from the demand side (power-to-heat, EV-charging), and it will be relevant both on a European scale (e.g. wind vs. solar regions, nuclear vs. hydro regions etc.) and more locally (e.g. integrating solar photovoltaics and electrified heat and transport). On the one hand, such pressure might increase because the pace of grid expansion does not keep up with the speed of transformation in generation and final energy applications. Cost and public acceptance could turn out particularly critical in this context. On the other hand, it might not be efficient to design an electricity grid for zero bottlenecks, as

[47] Maybe they influence dynamic decision making by car manufacturers, but this argument begs the question to what extent policymakers are responsible for, and capable of, actively shaping the industrial strategy of public companies.

inefficient utilisation rates might be an unwanted result. In fact, there is a trade-off between maximal connectivity and optimal utilisation levels. This trade-off will most likely find some degree of bottlenecks economically efficient – even more so considering the opportunities for efficient bottleneck management provided by flexibility technologies of all kinds, and by digital technologies for coordinating them.

As a result, bottlenecks on all grid levels will be a relevant feature of the future electricity system under strict decarbonisation, especially when nuclear and CCS do not play a significant role in the energy system. With bottlenecks, flexibility is a key lever to reduce total system cost. In particular, there will be an increasing need for local flexibility, including storage, power-to-heat, combined-heat-and-power (CHP) and, especially in the longer term, power-to-gas. Decentral optimisation will become more and more relevant as bottlenecks emerge in the distribution grid. Heat – by its nature a decentralised energy carrier - will play a pivotal role as it offers many relatively cheap short-term flexibility options, and, thus, can serve well for balancing[48]. Overall, one could integrate new gas-fired back-up capacities into decentralised heat-and-power-systems, making use both of the efficiency from CHP and of the flexibility in the heat sector.

Potential pathways for GHG mitigation similar to the ones described above, therefore, define two main challenges for regulating the electricity sector (beyond reducing its CO_2-footprint). Firstly, regulation must provide useful short-term signals, which efficiently balance supply, storage, and demand in an increasingly complex system topology, and allow for the use of digital automation as much as possible. Secondly, regulation needs to promote efficient and fast investment activity. Moreover, in addressing these two challenges, regulation must take into account the increasing interdependencies of the electricity sector with other sectors in the energy system, notably gas and heat.

3.1. Short-term incentives and coordination

Temporal resolution of short-term price signals has greatly improved on many wholesale markets across the EU, albeit not on all to a sufficient degree. By now, there are liquid intra-day markets in many member states, allowing market participants to react flexibly to intra-day deviations e.g. in expected wind or solar in-feed. Remaining minor design issues regarding temporal resolution on these markets include e.g. improved cross-border coordination[49]. So far, at least in Germany, the market could accommodate fast ramps in wind or solar production. The need for balancing capacity has not increased in spite of significant installations of intermittent capacity.

However, for most market participants, the temporal resolution of the wholesale markets does not translate into meaningful individual incentives to follow those signals. Even for market participants, who are real-time metered, the existing array of kWh-based fees, taxes,

48 E.g., hybrid systems for picking up excess RES-power with heat storage in water tanks, heat systems, or buildings.

49 For example, Paschmann (2017, Economic Analysis of Price Premiums in the Presence of Non-convexities – Evidence from German Electricity Markets, ewi Working Paper 17/12) finds that the exclusion of foreign bidders on the sub-hourly German intra-day market leads to systematic inefficiencies.

and levies, which augment the wholesale price, strongly distort the incentive provided by fluctuating wholesale prices. Removing such distortions therefore is a key prerequisite for including all flexibility options into an efficient dispatch regime. In particular, for the grid, this means moving towards a kW-based regime, valuing the maximal load connected to the grid, and including all users of the grid, and not only the final consumer. Levies, such as e.g. the German RES levy, should disappear, and the deficits financed through other instruments that are non-distorting to the electricity sector, e.g. kW-based levies or general taxation re-channelled through the state budget. Thus, the temporal perspective offers a separate argument for such fundamental reform already made above in the context of harmonising effective burdens from a CO_2-perspective.

Next to the temporal dimension, price signals also need to display an appropriate locational resolution in order to accommodate an increasing number of bottleneck situations. On the level of the transmission grid, systemic bottlenecks such as the inner-German bottleneck (North-East vs. South-West) can, in principle, be addressed by an appropriate design of the bidding zones, in an effort to minimize the need for centralised redispatch by the TSO. A cross-border redesign of bidding zones in Central Western Europe, for example, would improve dispatch decisions of generators, (pumped-hydro) storage operators and consumers. These improved decisions could avoid costly redispatch currently refinanced via a distorting levy on the grid fees.

However, one cannot make bidding zones arbitrarily small. In particular, market power issues and lack of liquidity are important trade-offs in this respect. As long as the EU sticks to the concept of decentralised dispatch based on market prices, centralised congestion management will therefore remain an important feature of the electricity market even after an optimal redesign of bidding zones, especially on the level of the distribution grids[50]. Current redispatch systems are insufficient for the purpose. In particular, they do not allow for the inclusion of all potential flexibility options down to the level of the distribution grids, and thus, they lack the spatial granularity required by the electricity system of the future. In particular, redispatch mechanisms should allow for aggregating flexibility options, and increasing their spatial granularity. Note that – in contrast to the current situation – TSO's as well as DSO's would engage in redispatch activity under such an improved mechanism.

Current EU legislation is mostly concerned with the wholesale markets, and increasing flexibility within them. However, on the wholesale level, flexibility does not appear to be, or to become, particularly scarce (except in very tight market conditions). The true value of flexibility in decentralised electricity systems based primarily on RES will result from congestion, by reducing the associated congestion rents and avoiding costly and inefficient grid expansion.

Overall, therefore, the design of redispatch mechanisms, as a major lever to address increasing instances of bottlenecks in the grids, proves to be a critical element of future market redesign. Under the current paradigm of decentralised, market-based dispatch, and given the various limitations to the minimum size of bidding zones, capturing this value will

[50] Moving to centralised dispatch constitutes an alternative, but it would require a significant overhaul of the EU rules on the internal market for electricity, discussed in more detail below

require an appropriate re-design of the one-sided redispatch markets connecting the grid operators to generators, storage operators and demand. Moreover, as long as EU member states maintain inefficiently designed bidding zones, it would be important to improve the cross-border coordination between TSO's in international redispatch.

3.2. Investment incentives and coordination

Transition pathways consistent with the EU climate targets require fast and enormous investment activities. For German electricity, the dena-scenarios identify between 57/59 GW (TM95/80) and 111/117 (EL95/80) of gas-fired capacity, and more than 300 GW of RES-based capacity, installed in 2050[51]. Even in the short-term until 2030, the scenarios ask for at least[52] 26/45 GW (TM/EL) of new gas-fired capacity, and at least 100 GW of additional RES-based capacity. Add to that the investments into electric appliances at the level of final energy: e.g., until 2030, at least 3 million new heat-pumps installed, a charging infrastructure for at least 22 million electric vehicles (BEV/PHEV)[53], and the required grid expansion for integration.

All these investments should take place as cost-efficiently as possible. Since the industry is grid-bound, there is an added challenge of investment coordination between the liberalised part of the market and the grid. Moreover, investments in the electricity system need to be coordinated with complimentary investments into the heat and gas sectors, respectively. Thus, investment coordination is required both vertically, i.e. within the electricity system, and horizontally, across infrastructures for different energy carriers.

In theory, given certain assumptions[54], short-term price signals from liquid, undistorted wholesale markets – including, of course, the ETS (or a carbon tax) for the emission mitigation part – should suffice to support the investment levels in the liberalised parts of the industry, which are required in long-term equilibrium (on the wholesale level, i.e. disregarding their geographical positioning). Over the past couple of years, the debate whether or not the short-term market[55] (together with the ETS) can guarantee a 'sufficient level' of capacity investments has raged high. Unfortunately, this debate has essentially come to nowhere, because critical evidence is missing[56]. It remains an open empirical question whether the short-term market in Europe will generate price signals – and price expectations – that would incentivise investment levels sufficient to avoid involuntary demand curtailment at all times.

[51] Given typical lifetimes, investment into these capacities would have to take place after 2020.

[52] Assuming capacities existing in 2015 have technical lifetimes extending to 2030.

[53] In the EL-scenarios the numbers are 6.6 million heat-pumps, and 24.3 million BEVs/PHEVs, respectively.

[54] Assuming, in particular, the absence of price-caps or other such state interventions, sufficient demand elasticity, and no bottlenecks in the grid.

[55] Note that the short-term market effectively trades capacity as well as energy. Hence, we prefer to use the terms short-term market/prices rather than the familiar but conceptually misleading term energy-only market/prices. The term energy-only is appropriate only for customers or contracts that are not real-time metered and thus do not allow for determining load profiles over time.

[56] Especially about the shape of the demand curve at high loads, and about the risk premium applicable to investments in the electricity sector. Key risk factors comprise, e.g., future subsidy schemes for RES and for back-up capacities, the future price for ETS-certificates, and the general commitment risk of the state with respect to future changes to the regulatory environment.

However, taking the spatial perspective and the more decentralised nature of decision making in a future electricity system into account, this debate appears relatively meaningless. Wholesale markets abstract from the underlying grid topology, inherently assuming a so-called 'copper plate'. This means that *even if* the equilibrium on the wholesale market were socially acceptable ('sufficient capacity'), bottlenecks within the corresponding bidding zone could still imply involuntary demand curtailment. In Germany, this challenge is referred to as 'system stability', and regulatory mechanisms are in place to keep generators online even if they are uneconomical at the wholesale level, and to incentivise investment into 'system-serving' new generation capacity. Currently, the TSOs and the Bundesnetzagentur, the regulatory authority, negotiate those mechanisms without much recourse to competition. Improved design of the bidding zones (see above) would reduce the need for such locational interventions. The bidding zone would exhibit a reduced number of instances of internal congestion, and, thus, the potential wedge between the capacity provided in a long-term equilibrium on the wholesale market and the capacity required to guarantee system stability would shrink. However, as soon as the spatial information needs to have a certain granularity – because of the granularity of the congestion – wholesale markets operating at an aggregate level of granularity, by construction, cannot deliver the appropriate investments. Then, there need to be investment incentives at a higher spatial resolution in order to compensate for bottlenecks in the grid, in order to avoid inefficient grid investment, and in order to make use of potential synergies with the heat and gas sectors.

On top of reconfigured bidding zones and an extended scope for redispatch mechanisms, the energy transition therefore requires mechanisms for incentivising investments into generation, storage, and demand flexibility at specific locations within the system. Investments need spatial coordination both vertically and horizontally, and at the sub-wholesale level. For such investment coordination, new mechanisms are required. In this context, then, the role of the system operators needs reconsideration. Unless the regulatory authority mirrors them completely, only the system operators are able to identify the appropriate locations within the electricity system, considering the trade-off between investment into the grid or into unregulated assets. For example, they could use regulated capacity auctions in order to obtain the required capacities. From here, however, new questions emerge, in particular: Which incentives make them fulfil this task without acting strategically? Would this imply stricter rules on unbundling? How are the auctions conducted by system operators coordinated horizontally and vertically, especially in countries with many system operators such as Germany? With so much centralised redispatch happening, how much value remains in keeping decentralised dispatch based on wholesale markets?

3.3. Fundamental review of the liberalised paradigm?

The current paradigm of liberalised electricity markets with regulated grids developed in the 1980's and 1990's. At the time, it addressed two major policy objectives: Allowing for an effective European integration of electricity markets on the one hand, and eliminating (static) inefficiencies in the electricity sector in order to reduce consumer prices on the other hand.

The new paradigm aligned with the objectives of the EU to apply the principle of the free movement of services and goods to the energy markets. Without market liberalisation, achieving this objective would have required an EU-wide cost-plus or monopolistic regime for the energy sector, with corresponding regulatory powers for EU authorities. Such a transfer of sovereign rights from the national to the European level would have been unthinkable in the 1990's, and it probably still is. Moreover, the great wave of expansion from the 1950's onwards, culminating in the construction of a large fleet of nuclear reactors, had subsided by the 1990's. Europe's electricity system was relatively new and with little projected demand growth. Everywhere in Europe, the great expansion happened under some form of cost-plus or monopolistic regime, guaranteeing fast and substantial investment, but at the cost of various forms of inefficiency. With the need for further investments into the sector diminishing, political attention could increasingly focus on short-term efficiency after 1990. In this situation, vertical unbundling, competition outside the natural monopoly of the grid, and incentive regulation for the grid could become the pillars of a new paradigm for energy policy.

Apart from its European dimension, the move from the monopolistic to the liberalised paradigm thus reflects the dilemma of infrastructure regulation under asymmetric information between the regulator and the firms. There is an inherent trade-off between cost-plus-regulation, encouraging investment, and incentive regulation with liberalisation, encouraging static efficiency. Competition between firms can provide a way out of the dilemma, but only if (temporary) capacity constraints are socially acceptable[57]. Moreover, in grid-bound industries, such as electricity, competition is not possible through all parts of the value chain, and the need to coordinate the investments into generation, storage, and grid further increases the advantage of cost-plus regimes, when there is a lot of investment activity going on.

The regulatory dilemma can also explain why there is a growing number of deviations from the strict liberalisation paradigm across the EU's electricity markets. For example, RES-subsidy schemes are effectively cost-plus, even with auctioning. The same holds for capacity remunerations. Also in grid regulation, cost-plus mechanisms have been introduced (e.g. investment budgets) in order to create investment incentives whenever policymakers were asking for fast expansion. Thus, currently, two paradigms coexist alongside each other. On the European level, there is the pretension of maintaining and improving a liberalised paradigm, harmonised across member states. On the member state level, however, governments erode this very paradigm by an increasing number of (selective) interventions contradicting its very premises.

Therefore, in the coming years, the EU will have to revisit some of the basic aspects of the current paradigm. For instance, the concept of decentralised dispatch decisions, coordinated by market prices, could give way to a centralised dispatch model, where regulation determines the remuneration for dispatch, e.g. based on nodal pricing mechanisms, and investments are coordinated via a system of auctions geared to always guaranteeing system stability. Thus, grid operators could assume a more influential role, also allowing for a more effective vertical and horizontal coordination of investments. The balance between cost-plus-regulation and incentive-regulation of such grid operators would likely have to change. Vertical unbundling would become even more important in such an approach, maybe

[57] Cf. the debate on investment incentives in electricity referred to above

favouring independent system operators closely cooperating with policy makers to achieve the politically set targets.

In such a regulatory system, European integration, thus, would no longer be achieved via markets but rather via the integration – or, at least, strong coordination – of the TSOs and the TSO-regulation. As in other policy areas, such integration is politically more difficult than the opening of markets across borders. Striving for 'perfect' integration should therefore not keep member states from action. Again, integration could happen at different speeds between various member states. For Central Western Europe, the cooperation within the Pentalateral Energy Forum would be a crucial starting point.

It is far beyond the scope of this paper to develop a full-fledged new paradigm for the regulation of EU energy markets. However, the next EU Commission should make a fundamental revision of the European approach to energy market regulation one of its key priorities. If it is true that a successful energy transition requires rapid, substantial investments into the energy system, then streamlining and clarifying the regulatory approach should become a priority for the EU. Carbon taxes are the main instrument to guide the transition, but systematically organised cost-plus elements need to accompany them in the electricity sector for the reasons discussed. In the face of these challenges, does the EU want to stick to the current liberalised paradigm in principle, while in effect giving more and more power to the member states and the regulatory authorities for micro-managing investments in an unorganized fashion? Or will the EU be able to conceptually redefine subsidiarity between the EU and the member states in a meaningful way, while devolving the task of investment support, and investment coordination, to the practitioners, for example to system operators?

4. Conclusion

European policymakers intend to move towards an energy system, which continues to provide secure and sufficient amounts of energy to a growing European economy but emits less and less greenhouse gases until effectively becoming (almost) carbon-neutral. Close examination of corresponding scenarios shows that this objective might be technologically feasible, but that it poses an enormous challenge even under favourable circumstances.

For making such a transition possible, the capital stock needs drastic restructuring throughout the entire economy. For example, the transition will affect many appliances for final energy use, the infrastructure for generating and transporting secondary energy carriers, as well as most buildings and the transport infrastructure. It must include significant investment by the state itself in infrastructure and subsidies for new capital stock or changed behaviour, if only to maintain social cohesion. Moreover, energy prices would have to increase substantially alongside with such a change of the capital stock in order to prevent counteracting rebound effects. Carbon pricing in the form of an increasing carbon tax appears to be the most important instrument, both with respect to engaging in reciprocal global cooperation based on a common commitment, and with respect to guiding European economies towards ever decreasing carbon emissions. At the same time, schemes for redistribution must accompany increasing taxes in order to compensate for the regressive effects and, thus, to buy social acceptance.

In the electricity sector, in particular, regulation needs to rebalance further towards cost-plus elements in order to accelerate the transition and allow for locational optimisation. Important issues include the boundaries between decentralised and centralised dispatch as well as the current unbundling rules. Especially in the distribution grids, the benefits of moving to a centralised dispatch might significantly outweigh potential efficiency losses, especially, if unbundling establishes truly independent system operators.

In summary, the analysis carried out in this paper suggests a fundamental revision of many tenets that have shaped European climate and energy policy over the past two decades. Among them: Adopting carbon prices instead of quantity targets for both reciprocal global pledges and mitigation inside the EU; overhauling energy tax systems including the ETS, the grid fees, and all other levies on final energy carriers, for the single goal of effective CO_2 reduction; systematically including more cost-plus-elements instead of efficiency-based regulation in more parts of the electricity sector. In general, the transition turns out to require a radical instead of a gradual view on the gradient of political change, including on the scope and size of redistributive measures.

Subsidiarity in EU climate and energy policy

The (explicit) political objectives for reducing CO_2 emissions and the (rather implicit) objectives for economic development and social cohesion together make for a political challenge of unprecedented size and urgency. There is some debate in the U.S. comparing the effort required to achieve such an energy transition to the national mobilisation during World War II[58]. However, even such a comparison might underestimate the scale of the challenge. The U.S. and their allies won World War II within the timespan of a few years; the energy transition, however, is a project for (at least) two generations. The mobilisation effort during the war affected several, clearly delineated industries; the energy transition runs right through the entire economy. Furthermore, importantly, the war effort reacted to an imminent and substantial external threat; climate change, by contrast, is a gradual process, and it involves a freeriding problem between sovereign nation states. Thus, legitimacy for drastic intervention might be harder to obtain now. Moreover, scarcities of raw materials were real back in World War II; fossil fuels, however, are not particularly scarce at present – which implies that, for CO_2 mitigation, policymakers voluntarily need to inflict such scarcity on the economy in order to encourage the energy transition. How do policymakers want to convince their populations to accept such rationing, especially, if other nations continue to expand their use of fossil fuels? Seen that way, even the enormous mobilisation effort of World War II appears to be a 'piece of cake' compared to the effort required for the energy transition. To what degree European societies are actually prepared for such an effort is unclear at present. Neither policymakers nor populations have so far acknowledged let alone accepted the degree and speed of change implied by the targets set. Thus, whether or not the

[58] Cf. e.g. Temple, 2018, At this rate, it's going to take nearly 400 years to transform the energy system, *MIT Technology Review.*

democratic process will actually come to deliver state action that is commensurate with the ambitious targets – which have been set without proper qualification and deliberation of their consequences and their interdependency with the behaviour of the rest of the world – remains an open question.

In any case, the EU neither has the mandate, nor the resources, let alone the public legitimacy to decide upon, and then to organise and implement such a mobilisation effort with all the associated interventions into tax systems, public infrastructure investments, and distributional policies. Besides, in the current state of affairs in European democracies, it would be the parliaments and governments of member states – rather than the European Commission and the European Parliament – to negotiate continuously the degree of intervention, and thus the actual (factual) scope and gradient of the energy transition with their respective electorates.

Therefore, the energy transition also requires a rethinking of the architecture for EU energy policy. Unless the EU becomes a sovereign state, it will fall on the member states to manage the challenges associated with the energy transition, in line with Article 194 of the Treaty of Lisbon. This means: either the EU acquires a new mandate including sovereign prerogatives currently reserved by member states, or the EU needs to give more leeway to member states in managing the energy transition in their countries. Reforming the national laws, and reprioritising national budgets, is difficult enough for national political leadership; compounding this task by forced coordination of action and strict adherence to narrow EU regulation makes this task harder still. Any such European coordination must create a tangible benefit overcompensating the added complexity. Otherwise, one should discard it. What is more important now, a timely energy transition or the efficiency potentially gained from an ever more perfect internal energy market? If the EU were a sovereign state, this trade-off obviously would not exist. In the current structure of the EU, however, the trade-off is real and needs careful attention.

Such considerations imply that subsidiarity should become the key organising principle for EU energy policy. The EU has an important role to play in global climate negotiations, working towards an agreement based on common commitment and reciprocity. Transparency about effective carbon prices within the EU would be an important starting point, inviting other parties in the UNFCCC to share their respective data. In this context, the EU should continue to organise member states' efforts in mutual commitments and effort-sharing agreements. On the interstate level, these commitments might continue to be volume-based with penalties, even after a shift to a carbon tax-based system within the member states. Towards the member states, the EU will persist in promoting cross-border trade and cooperation, for example with the projects of common interest. Furthermore, the EU could take a lead in developing import opportunities for 'green gas' with potential producer countries outside of the EU. However, the

EU should also devolve more power to member states in shaping their specific energy trajectories. Given the urgency and scope of the desired transition, the choice for the EU is between trying to create a "one size fits all" approach applying to all member states, thus risking slow change at best, or allowing for a broader spectrum of organizing principles adopted by (coalitions of) member states. In particular, the EU could revise state-aid rules to allow member states to define, organise and implement the transition effort, and to soften its distributional effects. Along those lines, the EU should in particular evaluate the usefulness of the EU ETS for implementing the transition. Replacing this system with pathways for carbon taxes (or, at least, carbon floor prices) across EU member states could greatly reduce complexity for market participants, create better visibility, and allow for a better alignment of (heterogeneous) national tax systems across energy carriers.

Subsidiarity will also be the key theme in organizing the electricity market for the transition. On the one hand, the EU continues to have the task of facilitating the creation of optimal cross-border bidding zones and enhanced TSO-cooperation. On the other hand, investment guarantees and incentives will continue to originate from member states, and they need to be coordinated with existing grid and demand/supply topologies, including, in the future, the heat and transportation sectors.

The current architecture of EU energy policy has its origins in a period of relative stability with limited investment needs into the energy system. In contrast, the next decades will require a wave of investment and enormous efforts to mobilise businesses and the population to make the energy transition move forward. Policymakers throughout Europe are employing a rhetoric of urgency and speed regarding the energy transition. If a fast energy transition truly has the priority that this rhetoric assigns to it, then regulation should heed it without unnecessary compromise. Since the energy transition is not supposed to wait for further political integration of the EU at a potential future point in time, member states should assume full responsibility and accountability for managing its implementation – now.

Chapter 3
Policies and markets fit for the decarbonisation of the power sector

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Introduction and executive summary

On 28 November 2018, the European Commission presented its strategic long-term vision for a "prosperous, modern, competitive and climate-neutral economy by 2050".[61] The Commission provides a set of forward-looking pathways for an ambitious decarbonisation of the European economy, which highlight the ongoing transformations in the energy sector, including the rise of new technologies and the change in consumers' expectations.

Given these trends, I have been asked by France Stratégie to evaluate how the current European energy policy could evolve to deliver on the decarbonisation policy objective whilst recognizing the technological and societal changes at play, with a particular focus on the regulatory framework and design of the electricity market.

In this paper I review the current market and regulatory framework in the European energy sector, which was defined in the context of the technologies, societal preferences and policy objectives prevailing in the 1990s and 2000s, and which will need a set of changes to support an efficient decarbonisation of the European economy. This paper is structured in four main sections:

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[59] The author would like to thank France Stratégie for its support in undertaking this study. The author is particularly grateful to Dominique Auverlot, Pr. Marc Oliver Bettzüge (EWI) and Pr. Dieter Helm (Oxford University) for very insightful exchanges during the course of the study.

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[61] Source: https://ec.europa.eu/clima/policies/strategies/2050_en

- I first focus on the principles guiding European and national energy policies. I identify the key issues raised by the current energy transition and I derive a number of recommendations for the evolution of the European and national energy policies and design of the electricity markets.

- As a second step, I put forward a number of potential evolutions of the current regulatory and governance framework in the electricity sector needed to deliver on the policy objectives. In the sections 2 and 3, I cover respectively the evolution of the policies driving decarbonisation in power markets and the organisation and governance changes necessary to foster a better local and regional coordination of policies affecting power markets.

- In the fourth and final section, I discuss the evolution of electricity markets towards a model characterized by competition in two consecutive steps, with 'competition for the market' in the form of tenders for longer term contracts followed by 'competition in the market' based on the set of existing markets.

In the next paragraphs, I provide a brief summary of these four sections and highlight some of the key policy recommendations.

First, I identify a number of evolutions in the approach toward European energy policy:

- First, the European policy approach to fighting climate change has been up to now largely focused on decarbonizing the power sector and there has been less progress on the different sectors emitting CO_2. Whist the decarbonization of the power sector will continue to be a priority, it is now well underway and the policy challenge is to tackle other sectors, such as heat in buildings, as well as the transport sector. A more holistic approach considering the benefits of horizontal sector coupling (e.g. between electricity and other primary energy sources such as gas) and vertical coupling (e.g. between energy sources and their end uses in transport and buildings) could provide significant benefits.

- Second, Europe's energy and climate policy in the past decade has been mostly inward looking. I argue that Europe needs to learn the lessons from the past decade and stress test its policies to a world in which non-cooperative strategies dominate the international agenda. For instance, Europe could consider implementing border tax adjustments for imported goods from countries which subsidise fossils fuels or do not enforce carbon pricing.

- Third, Europe has to date failed to define the policies driving the energy transition in connection with its industrial policy. The energy transition represents a significant opportunity for Europe to leverage its internal market and ambitious environmental policy in order to position itself as a leader in a number of key industrial sectors. Going forward, Europe should develop a more coordinated R&D and industrial policy for clean technologies through a wide-ranging reform of the SET-Plan.

- Fourth, Europe's decarbonization agenda needs to be reconciled with Europe's objective to support Europe' s competitiveness and contain costs for consumers. Energy policies will need to drive more engagement of people in order to create support for the energy transition. In addition, in a European and international context marked by growing economic and social tensions, the redistributive aspects of energy policies will need greater attention to maintain the public opinion support for decarbonisation.

In the second section of the paper, I focus on the reforms of the "policy mix" which was implemented in the 2000s to drive the decarbonisation of the power sector. The key issue for **policy makers is to credibly commit to a set of long term predictable policy objectives and implement a set of consistent and coordinated policies.** Ensuring inter-temporal consistency is always difficult for policy makers who are elected for a few years and make long term commitments. In practice, governments can rely on a range of mechanisms to firm up their long-term commitment, such as:

- First, a stronger and more predictable carbon price signal is needed as a foundation to anchor the credibility of long-term emission reductions targets from member states. The EU ETS could be complemented by a predictable long-term trajectory for a carbon price floor, and long-term carbon contracts with the states.

- Second, the various national policy and regulatory interventions that define the energy mix should be better coordinated (i.e. the phase out policies and support mechanisms targeted at some specific technologies). The lack of a coordinated approach results in a suboptimal mix of generation technologies and significant cost savings could be achieved by having even some limited coordination in setting targets and cooperation mechanisms to meet renewables targets for instance. This is also essential as the European electricity markets suffer from these interventions and ad hoc regulations which undermine market dynamics and prevent the market from sending efficient signals for investment / retirement to market operators.

In the third section of the paper, I focus on the governance of the electricity sector and the necessary evolutions to drive efficient investments to decarbonize the European economy given the new coordination and planning challenges for key infrastructures associated with the energy transition. I explain that the energy transition creates new coordination challenges between multiple stakeholders at different geographic levels (local, regional, national European) which will require a new approach towards infrastructure planning and the governance of the energy sector:

- The implementation of coordinated indicative planning processes in the long term to 2050 for critical infrastructures at local, regional and European levels is needed. There are several possible pathways for the European energy transition, and the absence of a common vision on the role for instance of different energy careers could lead to costly duplication of energy infrastructure and stranded assets in the future.

- Second, I argue that governance of the European energy sector will need to evolve to coordinate better the policies at the local, regional, and pan European levels. The role and mandate of the existing national regulatory agencies, as well as the national system operators, will need to be aligned with the need for a more holistic and cross sectoral approach. At the European level, regional bodies in key 'policy regions' will need to emerge to coordinate across neighboring countries key policy decisions affecting the common energy market and deployment of critical infrastructures. At the local level, local consultation and coordination processes will need to be implemented.

In the fourth and final part of the paper, I focus on the evolution of European electricity markets given the change in the cost structure toward fixed costs technologies, and the desire of policy makers to continue to determine the energy mix. I discuss the evolution of electricity markets towards a model characterized by competition in two consecutive steps, with 'competition for the market' in the form of tenders for longer term contracts followed by 'competition in the market' based on the existing markets:

- The first step involves the tendering of long-term contracts based on the policy targets and coordinated indicative planning conducted by policy makers. Such long-term contracts could be based on different products depending on the local electricity system needs and should be well articulated with the existing markets to minimize any possible distortion. For instance, when such contracts are linked to energy, contracts for differences could be a possible approach; another possibility is to anchor such long-term contracts on a different product such as capacity, for instance via long term capacity contracts. In any case, the objective of such long-term contracts is to facilitate investment and financing of low carbon technologies which are capital intensive. These long-term contracts should be tendered to concentrate competition on the investment decision, which is the most important cost factor for capital intensive technologies. Such long term contracts could have negative effects on competition and care needs to be given to ensuring that they comply with European competition policy.

- Capacity mechanisms have become widespread across Europe in recent years and will likely remain in many countries a key pillar to organize this first step of competition 'for the market'. However, I argue in the paper that the current uncoordinated capacity mechanisms are creating significant additional costs for European consumers and recommend that a framework for cross border participation in capacity mechanisms should be developed. A necessary prerequisite is for countries and regulators to establish a legal and operational framework to deal with situations of joint scarcity across the borders, which required a political willingness to be solidary at times of scarcity. In addition, given the growth of intermittent renewables, capacity mechanisms will need to evolve towards 'capabilities markets' which would reward the different services that are valuable to the system operator in order to maintain the system stability.

- The second step in my market model involves competition 'in the market', which does have the main objective of coordinating the system operation by ensuring a least cost dispatch of the different resources. The foundations for efficient short-term markets are already established in Europe, but a number of improvements will be needed to deal with the growing amount of variable resources, as well as decentralised resources connected at different locations on the network. Price signals will need to reflect operational constraints and scarcity conditions as close as possible to real time. Europe needs to go further into integrating intraday and balancing markets, but that it also needs to consider reforms introducing better linkages between system operators' actions close to real time through ancillary services procurement and market signals. For instance that the valuation of reserves should be better co-optimized with energy markets in order to ensure that the opportunity cost of reserves reservation is reflected in energy prices - an approach often referred to as "scarcity pricing". The second area of improvement for energy markets is to ensure that markets provide better price signals to avoid and manage network congestion. The current largely national price zones lead in some countries to significant congestion and redispatching costs have been increasing in the past few years. Going forward, some form of local price signals for electricity and flexibility services will need to emerge in order to facilitate the integration of large quantities of variable renewable generation. Local flexibility platforms combined with location and time differentiated network connection and use charges are a promising way forward in this respect in Europe.

1. The need for an integrated and outward looking policy approach for the energy transition

There is currently much debate on the need for increased ambition regarding Europe's decarbonization targets. It seems therefore timely to revisit the achievements of the previous Commissions regarding the environmental targets for 2020 and 2030 in the context of the wider European energy and climate policy.

In the past decade, a number of changes in context have led European policy makers to revisit the relative priority of the different objectives characterizing the traditional trilemma of European energy policy: climate, security of supply and competition and competitiveness. The priorities evolved to put competitiveness and cost control on the top of the policy agenda, alongside security of supply as the Ukrainian crisis reminded policy makers of Europe's growing dependence on imported gas. This change of priorities has put under the spotlight some of the inherent tradeoffs between the different EU policy objectives which remain unresolved.

The current European policy debate about the policies to deliver on the 2030 and 2050 objectives appear very much framed as a continuation of the 2020 approach. This section argues that Europe energy and climate policy needs a major overhaul if Europe is to deliver on its increased ambition with regard to decarbonisation.

European energy, climate, innovation and industrial policies need to be integrated

European energy and climate policies have long been searching to strike a balance between a "trilemma" of objectives: environment and climate policy, security of supply, and the creation of integrated and competitive electricity and gas markets. In practice, however, Europe's climate and energy policy continues to lack an integrated approach. For instance, the 2018 reform of the European ETS was not integrated with the debate on the 2030 targets for renewables and energy efficiency, whilst there are some obvious interlinkages between the two.

Moreover, Europe lacks an industrial policy in the field of clean technologies. Europe has to date largely failed to define the policies driving the energy transition in connection with its industrial policy. The energy transition represents a significant opportunity for Europe to leverage its internal market and ambitious environmental policy in order to position itself as a leader in a number of key industrial sectors. Europe has for instance largely failed in the 2000s to grow and retain an internal solar PV industry, but could position for the next generation of solar technologies. There are also significant industrial stakes around the leadership for batteries and innovative storage technologies which would benefit from a coordinated European approach.

Europe's support for clean technologies has been concentrated on the deployment of some technologies which have received significant support in the past decade. This support for deployment of some technologies contrasts with the relative lack of funds available for research and development (R&D) in energy. In real terms, public spending in Europe on energy remains well below the amounts spent in the 1980s, and this does contrast with the industrial policies of other countries such as the US or Japan, which focus a greater share of public spending on R&D.

Going forward, I have argued in previous publications (Roques 2014) that Europe needs to develop a coordinated R&D and industrial policy for clean technologies through a wide-ranging reform of the SET-Plan. This would involve scaling up spending R&D and demonstration significantly, and a better coordination of the different national efforts to R&D. Europe should invest more in fundamental research and stimulate the development of collaborations between the public and private sector to stimulate and leverage private R&D.

An integrated European innovation policy should also focus on the funding and support for the demonstration and commercialization of innovation, an area where Europe lacks a supportive framework compared to e.g. the United States. As a concrete policy example, the renewables energy supply (RES) targets for 2030 and beyond could be complemented with a clean technology R&D target. This would require a certification and measurement process for R&D which would have the benefit to contribute to rationalizing and coordinating R&D spending across member states.

An outward looking policy addressing non-cooperative policies from Europe's trading partners

Europe's energy and climate policy in the past decade has been too much inward looking and based on contestable implicit or explicit assumptions about the future of global energy markets. Europe needs to learn the lessons from the past decade and stress-test its policies to a changing world in which non-cooperative strategies dominate the international agenda.

Europe's strategy to lead on the fight against climate change has been based on the assumption that other countries would follow and define their own targets for emission reduction and clean technologies deployment. However, there has been to date insufficient progress on the international scene. In addition, Europe's commitment for decarbonization and impact assessments were underpinned by the view that fossil fuel prices would increase steadily in the future. However, the discovery and production of large quantities of shale hydrocarbons in the US, has changed the global oil and gas market dynamics.

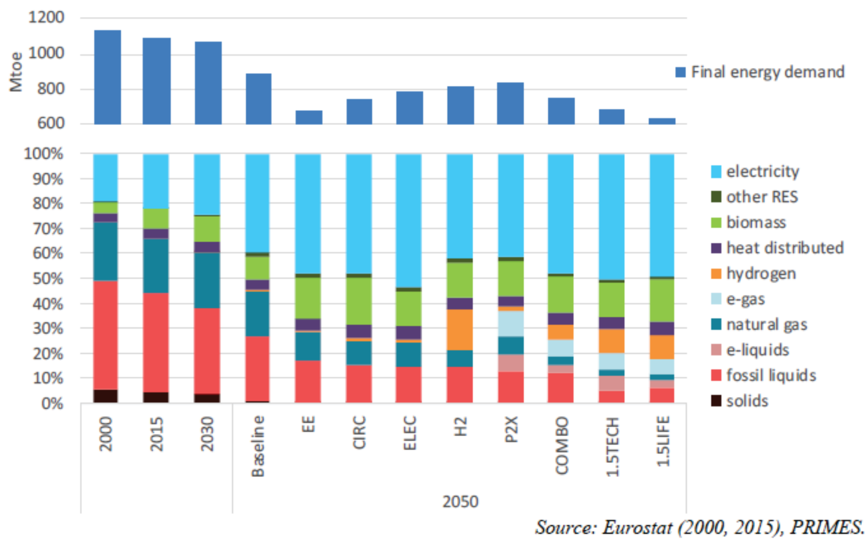
Moreover, current policies do not give any incentives to other countries to join Europe in the fight against climate change. Given this background, Europe's energy and environment policies should be stress-tested against scenarios with a non-cooperative approach from Europe's commercial partners in the fight against climate change, and with lower fossil fuel prices than currently anticipated. Europe could consider for instance the implementation of border tax adjustments to support the competitiveness of its industry in the context of rising carbon costs if its major trade partners are not enforcing their own carbon pricing legislation and/or keep subsidising fossils fuels. Similarly, supporting sectoral approaches towards climate commitments on a global basis could be a way to enforce a level playing field.

A holistic approach across sectors and end uses to leverage the benefits of sector coupling

For the past couple of decades Europe's energy policy has considered electricity and gas market policies as separate issues. The legislative and regulatory framework were developed largely on separate tracks with little account for the interfaces. Similarly, there has been little focus on the interdependencies in the regulation and market structure between different end uses such as transport, industry, and the decarbonisation of electricity and e-fuels. I argue that a more comprehensive and holistic approach recognising the interlinkages between different sectors and end uses is needed for an efficient decarbonisation.

The European Commission analysis of the different scenarios possible for an efficient decarbonisation published in November 2018[62] illustrates the wide range of uncertainties characterising the outlook for the European energy sector as well as the need for a holistic approach on the role of different energy carriers. Three of these scenarios analysed are driven by different decarbonised energy carriers, namely electricity, hydrogen and e-fuels (such as power to gas). The impact on the utilisation and need for reinforcement of the existing gas and electricity infrastructure varies greatly across scenarios.

Figure 1 – Share of energy carriers in final energy consumption in European Commission 2050 scenarios



Source: European Commission (2018). A Clean Planet for all: A European strategic long-term vision for a prosperous, modern, competitive and climate neutral economy. European Commission, November 2018.

62 European Commission (2018). A Clean Planet for all: A European strategic long-term vision for a prosperous, modern, competitive and climate neutral economy. European Commission, November 2018.

The different scenarios how a significant uncertainty on the role and nature of the different energy carriers in the long-term creating challenges for planning the future of the energy system infrastructure. This suggests that the continuation of a siloed approach focussed on decarbonisation policies for the different sectors or end uses will likely not succeeded in providing the adequate incentives for efficient and timely decarbonization.

Instead I recommend a shift in the approach to Europe's energy system planning and regulation to foster a comprehensive and holistic approach.[63] Sector coupling binds together power and end-use sectors to provide greater flexibility to the energy system so that decarbonisation can be achieved in a more effective way.[64] Sector coupling includes:

- *End-use sector coupling* which involves the electrification of energy demand while reinforcing the interaction between electricity supply and end-use;
- *Cross-vector integration* which involves the integrated use of different energy infrastructures and vectors, in particular electricity, heat and gas, either on the supply side (e.g. through conversion of (surplus) electricity to hydrogen), or on the demand side, e.g. by using residual heat from power generation or industrial processes for district heating.

The combination of end-use sector coupling and cross-vector integration could provide some benefits in the transition to a low-carbon energy system in some countries. However, power and gas sector coupling will compete with a range of other options to provide the different services to the energy system. For instance, the flexibility of the gas system will compete with other short-term flexibility options in the power system such as electricity storage (batteries), or demand response. Similarly, gas power plants dependability will compete with other dependable resources. Therefore, the regulatory framework will need to establish a level playing field across technology options. in addition, a differentiated approach towards sector coupling across countries is likely considering the local specificities of the energy system and the different costs and benefits associated with different types of approaches.

An efficient sector coupling will require a regulatory and market framework that relies on a number of core principles:

- Recognise the different sources of value provided to the energy system by different energy sources and infrastructures in a holistic perspective – in particular some of the externalities not valued today in the current market and regulatory framework will need to be explicitly taken into account;
- Establish a level playing field for different energy sources and infrastructures to provide / access these different services;
- Re-examine the market and regulatory framework to stimulate competition and innovation between energy sources and infrastructures to provide the different services needed by the energy system;

[63] See for instance FTI-CL Energy (2018), "Measures for a sustainable gas market", a study for GIE.
[64] See for instance, Fabien Roques *et al.* (2018), FTI-CL Energy "Study on the Role of Gas in Belgium's Future Energy System".

- Revisit the governance of the energy sector and the indicative planning mechanisms to foster a holistic approach to infrastructure development.

A first step towards reforming the regulatory and market framework for gas and electricity would consist in addressing some of the concrete barriers to sector coupling. Examples of such barriers include:

- Gas network charging approaches. The operational flexibility of gas power plants in some countries may be hindered by the lack of gas network transport products tailored for a more volatile operation.

- Electricity transmission charges for power-to-gas and electricity storage. These installations are often classified as a generation asset, and as such incur double Transmission Network Use of System (TNUoS) charges. The introduction of differentiated network charges for storage and / or activities with a sector coupling function and/or which are interruptible could be considered.

- Uncoordinated approach to crisis management / joint scarcity in the power and gas sectors. Some countries apply the European gas security of supply regulation in a way which could prevent power plants from accessing the gas at these times as domestic customers may be prioritised. The European commission could enforce a joint approach toward the risk preparedness plans for electricity and gas sectors to ensure that limits to the use of gas by power plants result in a critical situation in the power sector.

- Taxation may not be following the principle of taxing the end consumers, which can result in an unlevel playing field for some technologies. This can for instance affect Power-to-Gas and storage installations, which are classed as and end consumer in some countries and so incur tax. In the specific case of infrastructures having a sector coupling function, the European Commission could provide guidelines for a specific approach with regard to taxation.

- No common definition / tracing system for guarantees of origin for green gas. There is currently no harmonized approach for the use of Guarantees of Origin (GoO) certificates for green gases in different countries (including hydrogen).

Addressing distributional impacts of the energy transition to ensure social acceptability

Europe's decarbonisation agenda needs to be reconciled with Europe's objective to create competitive and integrated electricity and gas markets. Energy transitions have profound social implications which are often underplayed and can comprise the social acceptability and public support for the transition. Energy historians have documented the widespread societal ramifications associated with past energy transitions.[65] The 2018 protests against fuel price increases in France, and the growing opposition in a number of countries against some clean technologies which are key for the synergy transition (smart meters, wind farms,

[65] Clark A. Miller & Jennifer Richter (2014), Social Planning for Energy Transitions. Sustainable Renewable Energy Rep (2014) 1:77–84 DOI 10.1007/s40518-014-0010-9.

CCS, etc.) suggest that Europe needs to include a social dimension in its policies driving the energy transition in order to make it suitable and socially acceptable.

European and national energy policies often fail to incorporate the social dimensions of energy systems change. Major national energy policy and planning documents, for example, have concentrated almost exclusively on energy technologies. When social considerations have been taken into account, Europe has had a narrow focus on energy prices, jobs created in energy industries, and, to some extent, energy access. While these are important aspects of social planning for energy transitions, they significantly underestimate the depth and breadth of social issues at stake in large-scale transformation of energy systems.

The new European Commission and member states will need greater focus in shaping their energy and environmental policies on social impacts to enhance social mobilization around energy. Every major form of energy production is currently subject to social protest and conflict. In the face of these challenges, energy policy and planning need to rapidly develop new capacities for assessing and governing the social dimensions of energy transitions. Energy policies will need to support and drive engagement of people, forms of cooperation between government and citizens, between consumers themselves in order to create support for the energy transition. I therefore recommend that Europe should identify a number of best practices for stakeholders and citizens involvement on energy and environmental policy issues and provide guidelines and support to the different states but also local constituencies.

In addition, I recommend that the ways in which the energy transition costs are financed could be revisited. It has so far been widely accepted that each sector should have its end consumers pay for the costs of its decarbonisation. However, since the burden of the decarbonisation has been uneven across sectors, policies considering the financing of the decarbonisation costs in one sector independently of its contribution to the decarbonisation of other sectors may risk providing inefficient price signals to end users – for instance to switch to other forms of energy which are less costly as they have so far done little to decarbonize. I believe that three key issues will need to be addressed:

The first issue is to define how much of the costs associated with the decarbonisation of one sector should be borne by end users and how should be passed onto tax payers. If decarbonizing some sectors of the economy can be considered as a public good as it is essential to mitigate global warming and leads to global economic benefits, a greater proportion of the costs of decarbonization could be borne by governments directly via the state or local budgets.

The second issue consists in recognizing explicitly the role that some sectors play in a sector coupling perspective to decarbonizing other sectors, by ensuring that some of the costs associated with decarbonisation are borne by the consumers in the other coupled sectors. The ultimate objective should be to neutralize inefficient incentives to switch from one energy carrier or technology to another energy carrier or technology based on a narrow sector application of the cost causality principle.

Finally, redistributive policies as well as financing support mechanisms will need to be considered in order to ensure the social acceptability of the transition. Some guidelines and examples of best practice could be developed at the European level to support both members states and local constituencies implementing such policies.

2. Policies driving the decarbonisation of the power sector: The need for more coordination and long term commitments

In this section I turn to the toolbox of European energy policy and identify some of the issues with the policy tools that have been implemented in the different member states to deliver on the 2020 objectives. I argue that a stronger and more predictable carbon price signal is needed as a foundation to anchor the credibility of long-term emission reductions targets from member states. Moreover, the current patchwork of national policies to support some clean technologies will need to be further coordinated, both at a European and at the regional level.

Carbon pricing instruments beyond the ETS to provide a long-term carbon price commitment

The European Trading Scheme (ETS) was championed by the European Commission as the centerpiece of European policy toward a decarbonized energy mix.[66] The recent ETS reform led to a recent increase of carbon prices, which had been trading at low prices between 2009 and 2017. Over that period, weak and volatile ETS prices in were not effective in driving carbon emission abatement in the power sector. In a longer term perspective, current ETS prices are also held to be well below the kind of carbon prices that are needed to make investment in clean technologies competitive.[67]

The recent ETS reform, which among other measures introduced a 'market stability reserve', may not be sufficient to rebalance the market and ensure a sufficiently high and predictable carbon price for an efficient transition. I have evaluated the impact of various approaches for reform of the ETS in a previous study (Roques, 2016).[68]

A key issue that remains to be addressed is the overlap of the ETS with national policies in support of low carbon technologies and energy efficiency which have a significant effect on the demand for ETS allowances. In concrete terms, the issue is that the ETS has become a "residual market" for carbon abatement in the power sector.[69] Policies in support of renewables or nuclear have indeed been the prime drivers of power sector investments over the past decade in Europe.

[66] The European carbon Trading Scheme (ETS) currently covers close to half of the European Union's emissions of carbon dioxide (CO_2).

[67] Assuming a 140€/MWh cost of production for wind offshore and a 210€/MWh cost of production for solar PV, the implied carbon price that would equalize their long run generation costs with a combined cycle gas turbine (about 70 €/MWh) are respectively 240 €/tCO_2 and 430 €/tCO_2.

[68] See Roques et al. (2016), published as FTI Intelligence paper "Wake Up! Reforming the EU ETS: Comparative Evaluation of the Different Options".

[69] See "The ETS: a residual market for carbon abatement in need of a structural reform", Fabien Roques, April 2012.

As I argued in previous papers, the ETS needs to be supplemented by other carbon pricing approaches to provide some more credibility about a long term carbon price trajectory.[70] The ETS could for instance evolve toward a hybrid 'cap and trade system' with a price stabilization mechanism. This would require the implementation of a supply management mechanism or carbon price floor.

A supply management mechanism to maintain prices within a predetermined 'politically acceptable' price range would rely on a 'strategic reserve' of allowances which would manage the amount of credits auctioned each year to maintain ETS prices within a corridor. This could either be based on an improved MSR type mechanism, or delegated to an independent authority – e.g. a European carbon bank – which would have the mandate to adjust supply so as to maintain prices within a predetermined range.

Several countries are actively considering the potential of a carbon price floor (CPF) to complement the EU ETS and to strengthen the carbon price signal for investors. In a recent study, I analysed the impacts of a carbon price floor (CPF) implemented by a sub-set of European countries on emissions, power prices, renewable electricity investment, electricity trading flows and consumer costs (including costs for energy intensive industries).[71]

I concluded that a carbon price floor (CPF) could aid in the energy transition in Europe by driving greater coal to gas switching in the near term and enabling greater investment in renewable energy technologies (at lower cost of capital) in the medium to long term. Some of the key highlights of our analysis are summarized below:

- the CPF could act as an insurance mechanism for investors, protecting them against sudden ETS price drops caused by a significant demand/supply imbalance, and against potential weak macroeconomic conditions leading to oversupply and insufficient abatement. Our analysis, literature review and interviews suggested that a CPF could reduce the risk premium by around 1% point and thereby facilitate investment in capital intensive clean technologies.
- Renewables investment would be supported in a world where projects are increasingly exposed to merchant price risk. In addition, a CPF would drive greater coal to gas switching, and provide a clearer investment signal to avoid lock-in of fossil plants.
- Emissions in the CPF countries could be significantly reduced in 2030, and indeed reduced across the EU as whole.
- Electricity and emissions leakage through cross-border flows could be minimised by the MSR as well as complementary policy to maintain ETS demand levels, and through ensuring that the CPF zone is of a minimum acceptable size.
- Costs to consumers and industry would depend on power price impacts and may in fact be negative (i.e. savings) to the extent that the CPF enables greater investment in low

[70] See "European electricity markets in crisis:diagnostic and way forward", Fabien Roques, November 2012, contribution to France Stratégie report.

[71] See Roques *et al.* (2018), published as FTI Intelligence paper "Study of a Carbon Price Floor in European Countries: Analysis of Power Market and Consumer Impacts", November 2018.

carbon, low marginal cost generation capacity (the "merit order effect"). If there are additional costs to energy intensive industries and a risk of carbon leakage, the revenues raised through the carbon price floor could be used to compensate these industries.

Whilst one cannot expect all European countries to be supportive of such policy initiative, I argue that such a carbon price floor could be implemented by a 'coalition of the willing countries' on a regional basis and gradually extended. The Dutch proposal for a carbon price floor could be the catalyst for a common approach across France and the Benelux, which could be eventually extended to the Nordic countries and Germany.

In addition to a carbon price floor, long term carbon contracts could also play a critical role to reduce the long term commitment to a rising carbon price and the lack of confidence in the ETS and support investment in clean technologies.[72]

Coordination of the deployment of clean technologies and storage

By intervening in the integrated electricity market to support clean technologies, policy makers change the distribution of revenues to the existing assets, reducing both the running hours of thermal plants and the expected power prices. This had led across Europe to significant revenue transfers across technologies and across borders as the system adjusts the generation mix to reach a new equilibrium.

In addition, the lack of coordination between the national approaches has led to an uncoordinated deployment of renewables, with a strong build up in some regions that are not necessarily corresponding to the best endowed in terms of wind or solar resource, thereby increasing system costs for European consumers.[73] The EU Renewable Energy Directive 2009/28/EC encouraged cooperation between Member States for the 2020 target and put in place a number of cooperation mechanisms between member states and with third countries, but these have had to date little impact.

This lack of a coordinated approach results in a suboptimal mix of generation technologies and significant cost savings could be achieved by having even some limited coordination in setting targets and cooperation mechanisms to meet renewables targets for instance. Significant gains could be obtained by coordinating the various national interventions to define the energy mix through a set of emission standards, norms and support mechanisms targeted at some specific technologies.

The potential benefits of greater cooperation in RES support policies are wide ranging and might include: i) closing a potential gap with the RES targets and/or lowering the costs of reaching these RES targets; ii) cooperation for technology development; and iii) long-term cooperation for market integration through electricity imports/exports. A study commissioned by the European Commission attempted to quantify the potential benefits of improved

[72] See Carbon Contracts and Energy Policy: An Outline Proposal, Dieter Helm and Cameron Hepburn October 2005, available at: http://www.dieterhelm.co.uk/sites/default/files/CarbonContractsOct05.pdf

[73] See e.g. Roques, Fabien & Hiroux, Céline & Saguan, Marcelo, 2010. "Optimal wind power deployment in Europe--A portfolio approach," Energy Policy, Elsevier, vol. 38(7), pages 3245-3256, July.

cooperation between member states for renewables deployment.[74] The study estimated that support expenditures that come along with dedicated RES support would decrease by 10.8% in the case of a strong use of cooperation mechanisms.

I recommend that member states work together with neighboring countries – possibly within policy regions as proposed in the next session – to define RES deployment roadmaps which would comprise among other things an anticipated trajectory for the volumes of the different technologies to be added into the system As a starting point, one could envisage a regional approach where some countries could establish a pilot scheme and work with neighboring countries to define joint implementation plans for meeting the 2030 targets and develop a template for cross border recognition of renewables projects towards the national targets..

The discussions on the implementation of the Clean Energy Package could for instance usefully focus on the practical design of RES cooperation mechanism to remove the existing of perceived barriers to their implementation[75]. Going further, the EC could also think of ways to create incentives for countries to participate in such cooperation mechanisms, e.g. by adding a bonus in the accounting of renewables generation from projects involving cooperation across members states in their contribution toward the 2020 and 2030 targets.

3. Enhancing planning and governance for key infrastructures across the local, regional and European levels

The ongoing transformation of the electricity industry with the development of decentralised generation, storage, smart grids and active consumer participation are having a significant impact on the functioning of the European power system and will require a rethink of the governance and institutional framework to foster greater cooperation on a local and regional basis.

Before the 1990s and the liberalization of European electricity and gas markets, energy policy in the different member states was largely determined through central planning exercises at a national level involving governments and the key stakeholders. In the past two decades, a double dynamic has led both the local level and the European levels to become increasingly as important as the national level in shaping energy policies across Europe.

The growing importance of both the local level as well as regional and European levels in shaping energy policy in Europe have increased considerably the complexity of policy making. One of the biggest challenges is to ensure the consistency of policies implemented across these different levels of decision. This raises questions about whether the current governance mixing the national level with the local and regional/European level is optimal,

[74] "Cooperation between EU Member States under the RES Directive", Task 1 report. By: Corinna Klessmann, Erika de Visser, Fabian Wigand, Malte Gephart, Ecofys, and Gustav Resch, Sebastian Busch, TU Vienna. 29 January 2014. A report compiled within the European project "Cooperation between EU MS under the Renewable Energy Directive and interaction with support schemes".

[75] The design features could include for instance the type of cooperation (e.g. number of involved parties), the scope of cooperation (e.g. technology and duration of support), the flow of support (e.g. determination of support level/transfer price) and the contractual arrangements (e.g. arrangements for noncompliance).

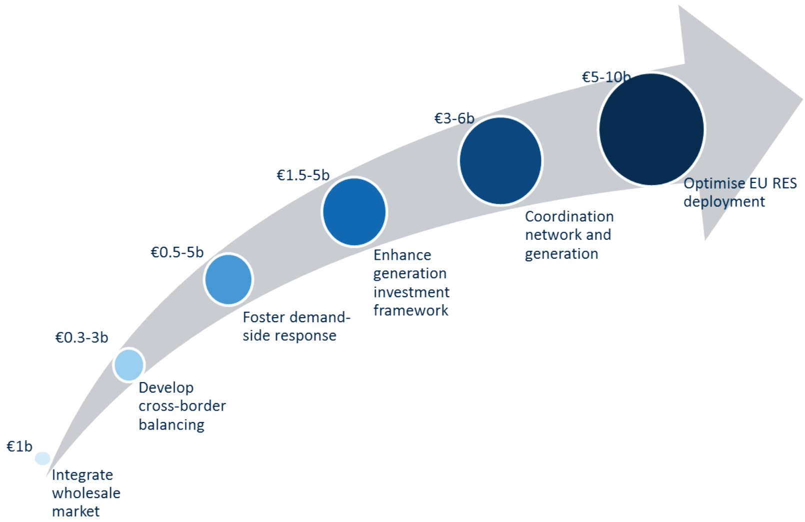
and how it could be improved further to adapt to this new dynamic toward regionalization and Europeanization.

Potential gains associated with greater coordination of policies

There are significant potential economic gains associated with a more coordinated approach toward the planning of investment in key energy infrastructures. Figure 2 is based on a survey of the academic literature, and shows the expected financial gains associated with different types of coordination measures at the European level. Figure 2 shows that the integration of the wholesale electricity markets is delivering roughly 1 billion Euros savings per year for European consumers.

Most importantly, the survey presented on Figure 2 demonstrates that much greater economic gains could be achieved via European coordination of the deployment of network infrastructure, as well as greater coordination of investments in generation. I already discussed cooperation mechanisms across countries for the deployment of clean technologies in the section 2 and will focus in this section on some of the key areas for reform to enhance the planning and the governance of critical European infrastructures.

Figure 2 – Orders of magnitude of the potential gains associated with different types of reforms (EU wide, billion €/year, based on a literature review)



Source: Fabien Roques, based on survey of academic literature

Local policy and market platforms to coordinate the energy transition at the local level

At the local level, local communities have become more engaged in the past few years in shaping energy policies. Whilst the role of municipalities varies greatly across member states, the development of decentralized generation on the one hand, and the more active outreach to energy consumers on the other side to stimulate demand response and active demand management have contributed to changing the perception of energy production and distribution. There is a growing interest from consumers and citizens to engage on energy issues, and municipalities or associations of consumers are gaining a prominent role in shaping energy policy at the local level.

Going forward, the role of distribution network operators (DSOs) will be central at the local level to coordinate and optimize the production and consumption of electricity at the local level. DSOs will also have a key role in the deployment and operation of smart grids and in providing access to the data that will be essential for suppliers to provide innovative services. This raises a number of questions regarding the governance and regulation of DSOs.[76]

Moreover, markets will also likely have a growing role to play at the local level. The development of local trading platforms for flexibility can provide useful market signals to coordinate the efficient activation at the local level of different flexibility resources based on an economic merit order. This would create in turn a number of challenges and issues to coordinate activation of flexibility resources at the local and national / European levels. The analysis on these new flexibility platform solution as a local flex market and their interaction with the current European market design will be a key area for research and innovation in the years to come.

Policy regions and policy roadmaps to foster regional cooperation

As regard to the European level, the Third Energy Package created new institutions which play an important coordination role, namely ACER and ENTSOE and ENTSOG. In addition, informal discussion forums at the EU level include the Florence and Madrid Forums. Going forward, there is a need to reinforce the mandate of these European institutions to allow better coordination across network and generation expansion, as well as to assess the impact of different national energy transition plans on the integrated power and gas markets.

Coordination at the regional level is a potential promising way forward and a bottom-up market integration process has been at work over the past years through the creation of the Regional Initiatives (RIs) and other, independent regional integration projects.[77] These work streams have led to a number of successes in regional market integration, such as the implementation of market coupling which started in the Center West Region and then spread across Europe.

Going forward, regional initiatives yield some potential significant benefits as a complement to the "top-down European driven" approach. First, taking into account country-specific circumstances and characteristics is difficult with 28 member states, and there is scope for closer energy policy cooperation of neighboring countries sharing some similar constraints – for instance countries sharing similar gas supply security issues. Second, some countries with joint interests and sharing similar policy orientations may way to move at a differentiated speed from the rest of the member states on some key issues, such as environmental policy. Third, regional approaches may prove an opportunity for bottom up involvement of all key stakeholders to find practical solutions to implement EU policies.

[76] See e.g. "From Distribution Networks to Smart Distribution Systems: Rethinking the Regulation of European Electricity DSOs", Sophia Ruester, Ignacio Perez-Arriaga, Sebastian Schwenen, Carlos, Battle, Jean-Michel Glachant.

[77] From Regional Markets to a Single European Market, Everis and Mercados (2010).

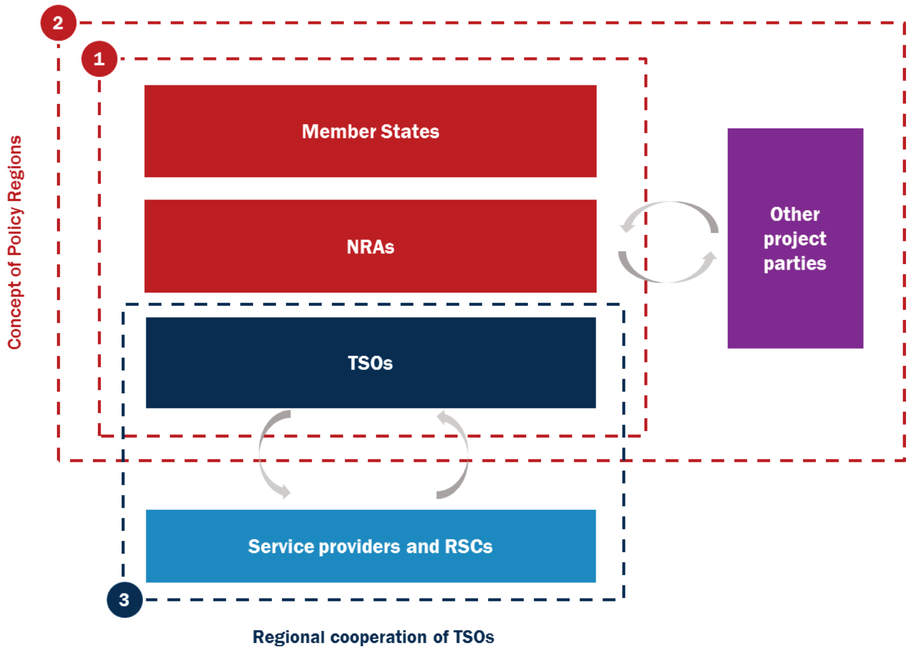
To foster a stronger cooperation for policy and regulation, I have put forward in a recent study the concept of policy regions, based on a three-layer coordination forum presented in the Figure 3 below:[78]

– *Coordination of policies and regulations*. A first forum of policy makers would involve member states and national energy regulators, as well as TSOs to the extent necessary, for focusing on the cooperation at the political level and on the coordination and harmonisation of policies and regulations to facilitate market integration and improve efficiency of these policies taking a regional point of view. Institutions such as the European Commission or ACER could also participate in this forum.

– *Consultation of stakeholders*. A second group would organise the adequate consultation of all relevant stakeholders, through dedicated meetings and workshops as well as public consultations. Stakeholder engagement is indeed a necessity to the concept of policy regions, to ensure a smooth and satisfactory implementation.

– *Cooperation of TSOs*. A third layer would focus on the coordination of TSOs in system and market operations and all TSO activities, for which regional coordination would be valuable, and look at the impact of policies on system and market operation and at the operational implementation of such policies, if necessary. This forum would in particular involve Regional Security Coordinators (RCCs) and other relevant service providers to TSOs or project partners (e.g. power exchanges, the Joint Auction Office etc.).

Figure 3 – Three-layer regional coordination framework for policies and regulations



Source: Fabien Roques and Charles Verhaeghe (2016), Options for the future of power system regional coordination, FTI-CL Energy report for ENTSOE

[78] Fabien Roques and Charles Verhaeghe (2016), *Options for the future of power system regional coordination*, FTI-CL Energy report for ENTSOE.

In addition to building the convergence of policies and regulations, the role of policy regions would also be to coordinate all the necessary decisions at national and regional levels to allow and facilitate the improvements of the regional cooperation of TSOs. Regional approaches could for instance play a growing role for governing EU renewables policy (see section 2). The objectives of such policy regions could be by increasing level of ambition (see e.g. Leonie Meulman and colleagues 2012[79]):

- to share information on investment plans relevant for all fuels used in the power generation/distribution sector and for infrastructure improvements.
- to develop some cooperation mechanisms on specific policy instruments, for instance a coordinated approach for cross border participation in renewables support schemes or capacity mechanisms.
- to coordinate or develop joint policy initiatives at the regional level, for instance discussion on security of supply or on environmental targets.
- to develop joint policy instruments, e.g. a common support scheme for renewables or a common capacity mechanism.

In order to ensure that policy instruments in the short term are consistent with medium to long term policy objectives, and in turn reinforce the credibility of these engagements, these policy regions could develop energy policy roadmaps and infrastructure development plans to 2050. These policy roadmaps would provide a forward-looking view of the required policy changes needed (e.g. carbon price evolution, timing for phase out of renewables support, etc.). The process to elaborate these roadmaps should be largely consultative and open to a wide range of industry stakeholders, both at a national level, at a regional level, and at the European level. Through a peer review process between member states at the regional and European level, inconsistencies could be picked up early and resolve early, ensuring greater confidence and credibility of the stated energy policy objectives. Last but not least, a process to assess regularly progress against the policy roadmap should be put in place. This would rely on a set of indicators, which would be periodically reviewed.

Expanded responsibilities of regional system operators for a better coordination of power system operation

The Third legislative Package[80] established the cooperation of TSOs, through a European entity, ENTSO-E (European Network of Transmission System Operators – Electricity), of regulators, through the European Agency for the Cooperation of Energy Regulators (ACER) and initiated the development of Network Codes and Guidelines. The system operation guideline (SOGL)[81] – and indirectly the Capacity Allocation and Congestion Management

[79] Meulman, L., P. Boot, C. van der Linde, J. de Jong and L. Werring, (2012), Harvesting Transition? Energy Policy Cooperation or Competition around the North Sea, Clingendael International Energy Programme, The Hague, January.

[80] Directive 2009/72/EC of the European Parliament and of the Council of 13 July 2009 concerning common rules for the internal market in electricity and repealing Directive 2003/54/EC and Regulation (EC) No 714/2009 of the European Parliament and of the Council of 13 July 2009 on conditions for access to the network for cross-border exchanges in electricity and repealing Regulation (EC) No 1228/2003.

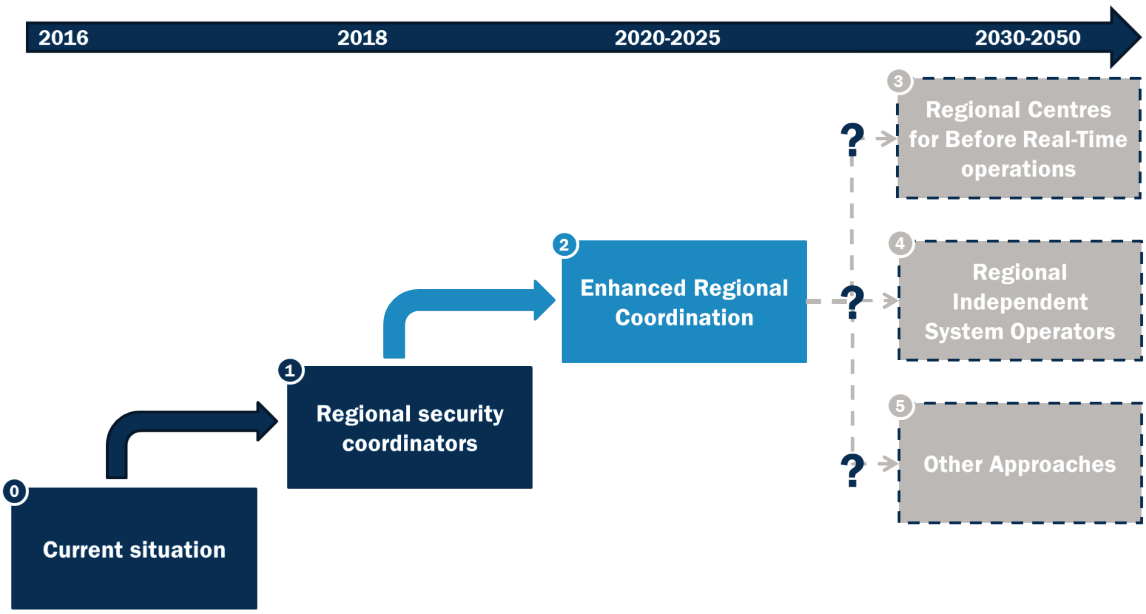
[81] Provisional final version of the Commission Regulation establishing a guideline on electricity transmission system operation.

(CACM) guideline[82] – foresee the roll-out of Regional Security Coordinators (RSCs), which will provide five core services to TSOs in the field of operational planning and capacity calculation. More recently, the 2018 Clean Energy Package contains a number of provisions which will contribute to expanding the roles and responsibilities of regional system operators.

However, an efficient regional coordination across European countries will require to go further in regional system cooperation. For the operational cooperation between TSOs, I proposed in a recent study (Roques, 2016, ENTOSE) an "enhanced regional coordination" (ERC) concept which builds upon RSCs and fully integrates the challenge of policy and regulation coordination, while allowing for an incremental and modular, but ambitious, enhancement of regional coordination in SO activities. In the ERC concept, the TSOs remain responsible for operational security and provided that coordination of regulations and policies is also improved, the proposed concept allows for RSCs to enhance TSOs' coordination by providing complementary analyses and by performing new coordination services.

The concept of Enhanced Regional Coordination (ERC) does not preclude any further evolution beyond 2030 towards other long-term solutions (e.g. toward more radical approaches such as ISOs). The proposed ERC approach is therefore a no-regret solution, which is a necessary first step in the evolution in the longer term towards different models for the operation of the European power system, as illustrated in the Figure 3 below.

Figure 4 – The concept of ERC as an evolutionary model for coordination



Source: FTI-CL Energy

Source: Fabien Roques and Charles Verhaeghe (2016), Options for the future of power system regional coordination, FTI-CL Energy report for ENTSOE

82 Commission Regulation (EU) 2015/1222 of 24 July 2015 establishing a guideline on capacity allocation and congestion management.

In the following paragraphs, I identify a number of concrete policy recommendations to expand the scope of services provided by RSCs to TSOs in 4 key areas, which could contribute to a more efficient operation of the European power system:

Cross border capacity reservation and allocation

There has been much debate in recent years regarding the reservation and allocation of cross border capacities. The main concerns that have been raised is the lack of coordination and adequate incentives for TSOs towards maximising the cross-border capacity, which causes inefficiencies and impacts downward possibilities for trading.

To address these concerns, RSCs' services, and most specifically capacity calculation, could evolve to address these issues. As a regional body, RSCs could perform some of these tasks with a "natural" regional point of view, whereas national TSOs have national oversight and scope. At this stage, RSCs have a coordination role with regard to capacity calculation, which is mainly to merge TSOs' inputs and perform computations out of these aggregated data. To further enhance capacity calculation and aim at maximising social welfare at the regional or European level, RSCs could provide useful analysis for capacity calculation. In addition, if RSCs had access to adequate information on all available remedial actions, and corresponding costs,[83] they could integrate remedial actions further in the calculation process.

Balancing coordination between TSOs

The development of RES and the reliance on cross-border exchanges reinforce the need and benefits resulting from balancing coordination. The implementation of the target model for balancing exchanges will follow – as it has been the case for market coupling for instance – a gradual sequence to extend the geographical scope of the common merit order list (CMOL), possibly with a regional approach. In this process, the coordination of TSOs will be key and RSCs could play a role:

- First, TSOs could analyse the possible gains of procuring services from RSCs in the context of the implementation of the electricity balancing guideline. RSCs could eventually play a role in the creation and in the coordinated operation of the balancing platforms.
- Second, RSCs could provide regional analyses for TSOs in order to investigate possibilities of sharing of reserves and enhanced dimensioning of balancing reserves, and also possibly to analyse the reservation of cross-border capacity for the exchange of balancing reserves, in compliance with the conditions set out in the SOGL.
- Lastly, the coordination of the procurement of certain types of balancing reserves could increase its efficiency, especially if there is a possibility of sharing or exchanging these reserves between TSOs.

Generation adequacy: towards a regional approach

Through interconnections, member states contribute to each other's generation and flexibility adequacy. Generation and flexibility adequacy therefore has a clear and strong European

[83] Costs might not be known in advance, especially during the capacity calculation process, but they may be able to develop estimations.

and regional dimension. That is why a strong level of coordination already exists amongst TSOs for performing generation adequacy forecast and ENTSO-E has developed and significantly improved coordinated methodologies and cooperation in that field, and these improvements may continue, for instance with the integration of a market module to reflect market participants' decisions on mothballs, closures and investments, and therefore to strengthen the robustness of forward-looking scenarios.

However, even if European-wide analyses are a good basis for adequacy assessment, they hardly capture local specificities (sensitivity to temperature, management of hydro systems, RES integration etc.), which vary depending on regions. As RSCs are developing a detailed knowledge of the power system at the regional level and will already be performing shorter term adequacy assessment (e.g. week-ahead), the elaboration of seasonal outlooks at least and possibly the assessment of generation adequacy in the medium term could be a "natural" prolongation of its activities. Thus, RSCs could perform generation adequacy analysis for TSOs at the regional levels, based on inputs from TSOs (evolutions of generation mix, including closures of plants and new build plants and RES scenarios, demand forecasts, grid developments).

Also, given the changes in system needs, flexibility adequacy assessment could also be integrated in the analysis; not only RSCs would look at generation adequacy at peaks, but they would also look at a number of situations where the system might be at stress due to the lack of downward resources, of inertia sources, or of flexible capacity for instance.

In addition, RSCs could also contribute to TSOs additional analyses to set up some of the parameters of possible system adequacy mechanisms, especially if they are implemented or coordinated at regional level, for example, the evaluation of the possible cross-border contribution at the borders, using detailed inputs and best estimations provided by concerned TSOs.

Network planning: taking into account cross border effects

The TSOs (or other responsible bodies where relevant), who have responsibilities to perform network planning and liaise with other TSOs/parties for network investments, could benefit in some projects from a regional approach to their assessment, e.g. though the use of a consistent modelling approach and a richer set of information.

Building upon the knowledge and expertise gained in operations by RSCs, RSCs could contribute to the process of investment planning for cross-border lines as well as internal lines with significant cross-border impact. One possible area is where the RSCs could perform cost-benefit analysis for specific regional projects, supporting proposals.

Coordinated infrastructure development plans and financing support at the regional and European level

The energy transition will require the deployment of new infrastructures, such as storage, electric charging stations, smart grids, or clean gas, electric fuels and hydrogen production, transport and storage networks. I argue that regulators and policy institutions will have a critical role to play in the planning and coordination of development of such infrastructures.

Progress on building interconnection and other critical infrastructures supporting market integration has been slow over the past two decades. This comes as a stark contrast to the ambition of the European Commission to step up the rhythm of key infrastructures such as interconnection as a critical facilitator of an affordable transition toward a low carbon electricity system.[84] The progress of key infrastructure projects has typically been slowed down by a range of factors including local opposition, as well as political and regulatory barriers. Most often the cause of the delays resides in authorization and permitting process and local opposition, as the coordination of different parties across borders is usually complex.

As mentioned earlier in this section, there would be significant benefits in having a more coordinated development of key infrastructures across Europe. I therefore argue that Europe needs to work on a set of measures to coordinate and fast track the construction of critical infrastructure. The EC should work to remove some of the permitting and licensing hurdles, through e.g. the creation of a one-stop-shop agency as part of ACER and/or regional planning committees for the approval of critical infrastructure projects.

I also suggest that the policy regions that I introduced in the previous subsection of this report could be tasked with the indicative planning across countries of the deployment of critical infrastructures such as storage, electric charging stations, smart grids, as well as infrastructures associated with clean gas, electric fuels and hydrogen production, transport and storage networks. These regional indicative plans should be defined by policy makers in a way that ensure engagement of the different stakeholders, in a process described in the previous section though the concept of 'policy region'. The European Commission could then ensure the consistency of these different regional plans with the European energy policy objectives, and provide some guidelines. In addition, the European Commission should also provide some guidelines and foster best practice to relieve local opposition, e.g. by working with local communities to create support for new projects through benefit sharing mechanisms.

Finally, financing could also be facilitated through the expansion of the current share of European funding for projects of Common Interest (PCI) projects to a broader set of infrastructures, as well as scaling up some of the recent EU funding mechanisms. The European Commission, the European Investment Bank (EIB) as well as the different member states financial institutions indeed contribute already significantly toward the financing for critical energy infrastructure. In addition to the direct contribution to providing debt and equity for investment in clean technologies and energy infrastructure, the European Commission and the EIB have for instance launched a "Project Bond Initiative" to facilitate the financing of critical infrastructure, which could in the future play a significant role to attract infrastructure finance into the European energy sector.

Going forward, I recommend that the European Commission and the EIB, together with the member states financial institutions, work together to scale up the amount of lending and equity financing available to Trans European Network and PCI projects. In addition, whilst

[84] ENSTO-E 10 year Investment Plan calls indeed for two- to threefold Increase in the rate of infrastructure investment, and anticipates €104 bn of investments in power grid infrastructure over 2012-22 (TK update).

the traditional ways of corporate and public) capital expenditure as well bank lending will continue to play a critical role, Europe will need to attract new sources of capital. Therefore, recognizing the limits of public funding at times of budget constraints, a major focus should be on exploring how the current regulatory framework can provide better incentives to private capital to the financing of infrastructure investment needs. There is scope for the development of alternative financing arrangements (such as public-private partnerships) and investment vehicles (such as project bonds and suitable investment funds).

4. Electricity market design: Toward a two-steps approach with competition "for the market" followed by competition "in the market"

Despite some steady progress toward integration of electricity markets across Europe, there remains much debate as to the need for a new approach toward electricity market design to attract investment in clean technologies and support the decarbonization of the European economy. I argued in previous reports (Roques, 2014) that the key issue is not so much the imperfect or incomplete process of liberalization and integration of European electricity markets, but rather the need to reconcile this process with the new policy priorities in favor of decarbonization and competitiveness. In this section, I explain the changes in policy objectives and technology paradigm which underpin the need for the evolution in market design toward a new model, before outlining the key features of this new market model.

The need for a new market model: implications of the change of policy objectives and technology paradigm

The theory for electricity market liberalization was developed in the early 1980s in a very different context from today. Electricity production had been characterized for decades by increasing returns to scale, and technologies with significant variable costs. I outline below the key drivers of change.

First, current electricity markets have been designed on the principle that electricity is a homogenous commodity produced by a set of fairly similar technologies (conventional thermal plants). The introduction of intermittent renewables requires a differentiation of the value of electricity produced from different generation technologies depending on a number of attributes: whether the production can be controlled, the degree of flexibility and predictability of the production are valuable attributes which lead to the creating of separate markets to value these different attributes. I detail in the next section the reforms of short-term electricity markets required to provide efficient signals for flexibility.

Second, the change in the cost structure of the dominant technologies has important implications for the evolution of the design of competitive power markets, as the European electricity industry is moving from an "OPEX world" into a "CAPEX world". Whilst in theory marginal cost pricing can still work with a part of the generation mix having zero or very low SRMCs, prices will likely become very volatile as the share of renewables increases and technologies with zero SRMC clear the market increasingly frequently. The risk is therefore that prices would be at or near zero (and could even be negative) for significant periods of time, and fixed costs for thermal plants would therefore have to be recouped during few hours, therefore leading to extremely high prices. The evolution of price dynamics will however depend on the development of storage, which could dampen the price volatility if it develops significantly in the years to come.

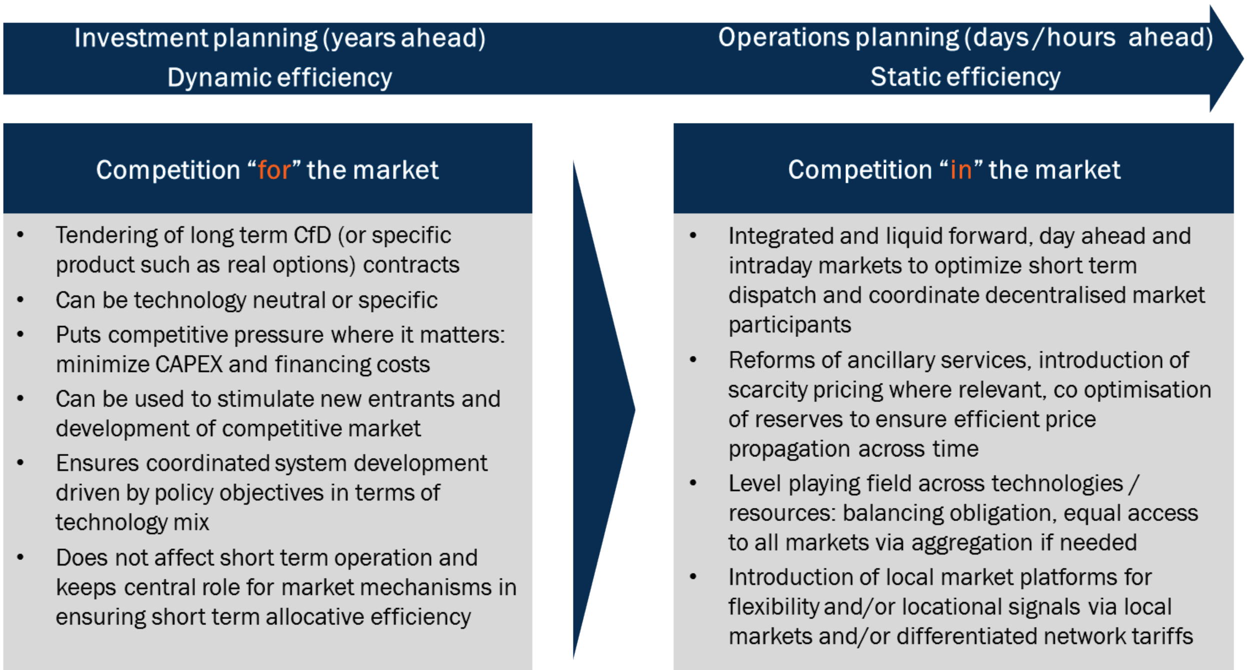
Third, it has become clear in the past few years that European countries are not ready to let the market decide on the resource mix and will continue to intervene in electricity markets to drive and orientate investment toward the technologies they chose. This suggests that the new approach to electricity market design will need to take as a given that price signals will not be the only diving force of investment and divesture decisions in the market. In other words, the planning of long lived energy infrastructure and decisions on the generation mix are likely to remain largely driven by policy decisions.

The gradual increase of the share of renewables should therefore be supported by reforms of the 'target model' for electricity markets in Europe. I detail in the next sections the new electricity market model that can take into account these changes of context.

1st Step – Coordination of investment through competition "for the market" via tendering of long term contracts

The model I propose is based on competition in two steps, with 'completion for the market' in the form of tenders for longer term contracts followed by 'competition in the market' based on the set of short-term markets that would enhance and complete the existing energy markets, as described on Figure 4.[85]

Figure 4 – A Blueprint for a two-step market design with competition "for the market" followed by competition "in the market"



Source: Fabien Roques (2015). FTI-CL Energy study "Toward the Target Model 2.0".

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[85] For greater details, please see Fabien Roques (2015), FTI-CL Energy study "Toward the Target Model 2.0".

The first step 'competition for the market' involves the tendering of long term contracts based on the technology and infrastructure indicative planning processes described in previous sections at the local, regional and Europe levels. Long term commitments would facilitate investment and financing of low carbon as well as storage and other flexibility resources. Long term contracts would be tendered to concentrate competition on the investment decision, which is the most important cost minimisation driver for capital intensive technologies. These long term contracts would be aimed at delivering efficient and coordinated deployment of clean technologies as well as storage and other flexibility resources, and would supplement the existing markets whose role would be confined to the short-term dispatch optimization.

Such long term contracts could involve different products depending on the local electricity system needs, but should be designed in a way that does minimize any potential distortions of the markets. For instance, when such contracts are linked to energy, contracts for differences could be a possible approach; another possibility is to anchor such long term contracts on a different product such as capacity.

As figure 4 describes, these contracts can be technology neutral or technology specific, based on some specific requirements defined based on the electricity system needs. For instance, in case the electricity system in a given country require more flexible resources, the tendering could include criteria linked to the flexibility of the resources and de facto exclude the technologies which do not correspond to these characteristics. A more technology neutral approach could be followed, but a system of derating would be needed to compare and assess the relative contribution of different resources in respect of this product.[86]

In fact, the implementation of such "two step" hybrid market approach would be the natural follow up from the current market design in which clean technologies are already largely tendered via long term contracts (often CFDs), and dependable resources awarded capacity remuneration contracts via tendering and sometimes long term contracts.

The move toward a systematic approach could therefore happen gradually as additional remuneration sources through short term markets and capacity markets gradually provide new sources of revenues reflecting the growing importance of these products to the system. The destination may therefore be a framework which ensure that there is competition 'for the market' and a level playing field between low carbon and thermal plants, whilst the spot and intraday markets would ensure competition 'in the market'.[87]

In practice, however, long term contracts can have negative effects on competition and care needs to be given to ensuring that they comply with European competition policy. In this perspective, the pro-competitive effects of such long-term contracts via their impact on financing should be weighed against their impact on against the potential negative effects and will need to be assessed by considering the relevant market structure.

[86] Dieter Helm has for instance proposed to establish tenders for firm energy contracts, which would be technology neutral but would involve a derating approach to compare the relative ability of different technologies to provide firm energy. Such derating approach would depend in turn on how the firmness of different technologies is defined (e.g. on an hourly basis or on average over certain periods, at the plant level or based on a portfolio of resources of one operator, etc.).

[87] For more discussion of these issues, see e.g. D. Finon and F. Roques (2013). European Electricity Market Reforms: The "Visible Hand" of Public Coordination, *Economics of Energy & Environmental Policy*, vol. 2(2).

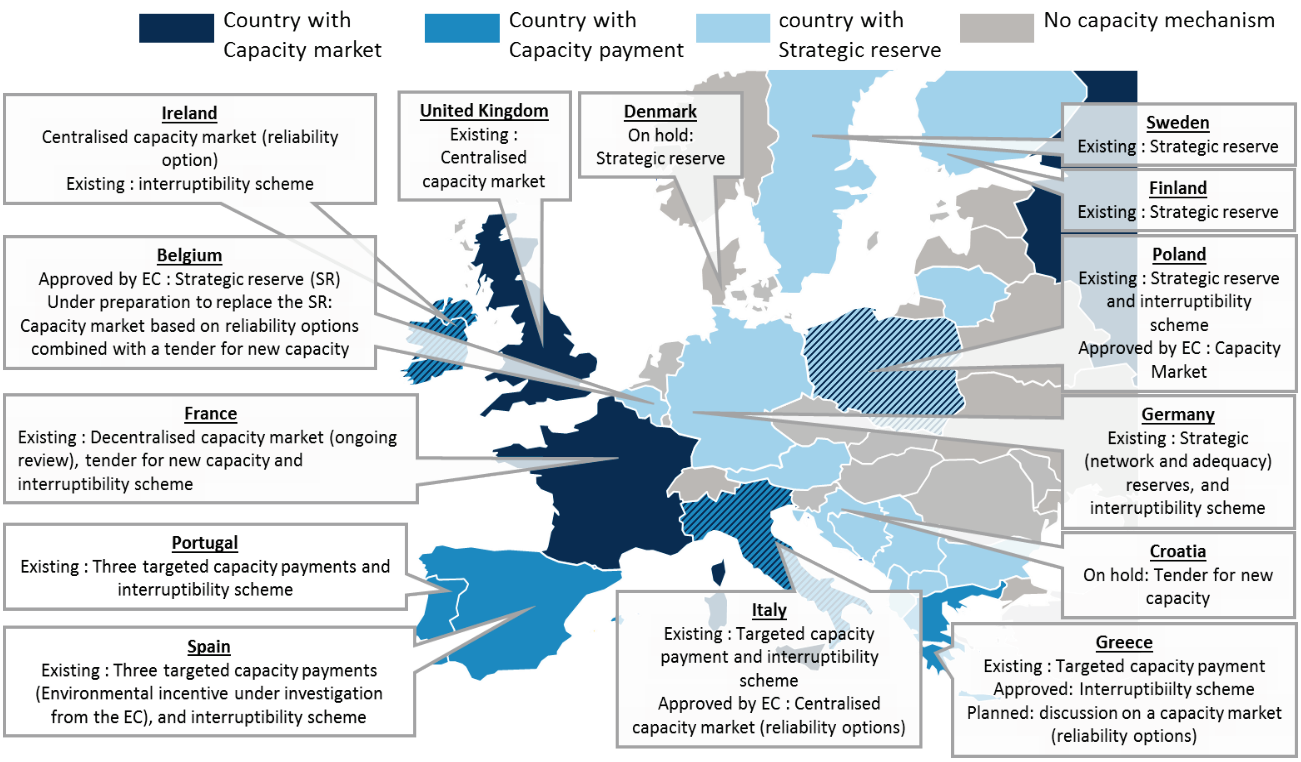
Capacity mechanisms: evolution toward regional coordination and reward of "capabilities"

Capacity mechanisms have become widespread across Europe in recent years and will likely remain in many countries a key pillar to organize this first step of competition 'for the market'. Indeed, capacity mechanisms often involve the tendering of long term capacity contracts for new resources or resources undergoing significant new investment as part of a refurbishment.

However, the current uncoordinated capacity mechanisms are creating additional costs for European consumers compared to a more integrated approach to secure electricity supplies. I therefore recommend a more coordinated approach and detail below the necessary policy and regulatory measures to work towards such coordinated approach across borders.

There is indeed currently much debate in a number of European countries about whether the lights will stay on in Europe as the new emission standards of the Clean Energy package combined with the plans for coal plants and nuclear plants phase outs in several countries will drive a significant amount of dependable generation capacity out of the market by the mid 2020s. Most countries have taken steps to introduce or reform a capacity mechanism, using different approaches. The result is a patchwork of different national capacity mechanisms which could undermine the further integration of European electricity markets.

Figure 5 – Map of capacity mechanisms in Europe



Source: Roques, F. (2019), "Counting on the neighbours: challenges and practical approaches for cross-border participation in capacity mechanisms", Oxford Review of Economic Policy, Vol. 35(2), Summer 2019, p. 332-349

I have explained in previous publications (see e.g. Roques, 2018) that the drivers of capacity mechanisms across Europe are different depending on the country considered, such that it is unlikely that a common approach at the Europe level will be practical or even suitable.[88] But I explained that there would be merits in working toward some degree of coordination in order to minimize the potential distortions associated with different capacity mechanism approaches.

I therefore recommend that a framework for cross border participation in capacity mechanisms should be developed. I list below a number of preliminary steps that would be necessary prerequisites for the coordination of capacity mechanisms across borders:

- A critical first step for a coordinated approach across European countries consists in defining explicit reliability standard criteria in each country and ensuring their consistency (e.g. loss of load expectation or target reserve margin). Many countries do not have an explicit security of supply standard, but rather rely on engineering principles to evaluate the necessary investments to upgrade or reinforce networks. These different security of supply criteria also imply that the issue of "capacity leakage", i.e. cross subsidization predates the implementation of capacity mechanisms, in the sense that countries which have a system dimensioned to stricter security of supply standard actually cross subsidize countries with a lower security of supply standard.
- Moreover, for countries which have an explicit security of supply criteria, the indicators used are different in nature (e.g. target reserve margin versus a target probability of lost load), raising the issue of the harmonization of the criteria and approaches used to derive them. European TSOs have been working as part of ENTSOE to spread best practice in terms of forward adequacy assessments, using probabilistic rather than deterministic assessments. As I discussed in the section 3 of this report, regional coordination of TSOs is necessary to define a common methodological framework for resource adequacy assessment.
- Another important issue is the necessary collaboration of TSOs ideally on a regional basis to define common certification and verification procedures for plants and DSM that will participate in capacity mechanisms across borders. This requires at minimum, a common registry of plants and other resources, as well as common approaches to certify and verify the availability of plants in line with the definition of the capacity product.
- Most importantly, TSOs will need to develop on a regional basis a common coordination framework, including operational rules, to deal with situations of joint system stress across borders. At time of capacity shortage in one or two countries, there need to be clear rules and corresponding operational practices in place to ensure the physical delivery of energy according to the commercial contracts that have been signed.

Separately from this issue of cross border coordination, I argue that the approach to evaluate security of electricity supplies will need to evolve with the growth of intermittent renewables to focus not just on adequacy, but also on flexibility. This implies that the adequacy

[88] Roques F. (2018), "Counting on the neighbours: Challenges and practical approaches for cross border participation in capacity mechanisms". Oxford Energy Review, in press.

assessment should be expanded to also evaluate the flexibility requirements. In the context of a growing share of variable renewables, the capabilities of different resources contributing to adequacy will need to be differentiated. Their value to the system can be explicitly captured through the evolution of capacity markets toward "capabilities markets" (e.g. ramping services, etc.) in which multi dimension auctions would allow System operators to select resources based on the weighted costs of supplying different types of capabilities.

Therefore, looking into the medium to long term, I argue that capacity mechanisms will likely need to evolve to remunerate the different services contributing to securing the electricity system, such as flexibility. Capacity markets will likely need to evolve towards 'capabilities markets' which would reward differently the different resources based on the different services that they provide and their value to the system operator in maintaining the system stability.

2nd step – Reforms to improve the "competition in the market" and support the development of flexibility

The second step in my market model involves competition 'in the market', and does have the main objective of coordinating the system operation by ensuring a least cost dispatch of the different resources. The foundations for efficient short-term markets are already present in Europe, but a number of improvements will be needed to deal with the growing amount of variable resources, as well as decentralised resources connected at different locations on the network.

Indeed, the development of variable renewable energy sources (RES) presents a number of challenges for electricity market design, which I have highlighted in previous research (Roques, 2016 IEA). Most importantly, the development of variable renewable energy sources will require a strong development of flexibility. There has been much debate in recent years on the ability of the current European electricity markets to provide adequate incentives for the investment in flexible resources such as storage or demand response.

The first area of improvement of current energy markets is to ensure that price signals reflect operational constraints and scarcity conditions as close as possible to real time. European power market integration has indeed largely focused on day ahead markets to date with the implementation of day ahead market coupling and has only recently shifted to intraday and balancing markets.

Incentives for the utilisation of flexible resources in the short-term and signals for investment in flexible resources in the long-term are mostly provided in the markets for energy and ancillary services. Europe needs to go further in developing liquid and integrated intraday and balancing markets to provide better incentives for flexible resources.

In addition, Europe could learn the lessons from the US RTOs/ISOs which have introduced several design elements in the short-term wholesale electricity markets to further improve valuation of flexibility in the short-run and in the long-run. More specifically, I recommend considering reforms introducing better linkages between system operators actions close to real time through ancillary services procurement and market signals that reflect more finely the operational capabilities of the different system resources and therefore their actual contribution to the system stability. I distinguish two groups of possible reforms:

- *Scarcity pricing mechanisms:* For efficient dispatch and investment decisions of flexible generating and demand-side resources, it is important that energy prices rise above the marginal cost of the last running unit in periods of system scarcity, i.e. periods of system stress (which do not necessarily result in load curtailment). I recommend for instance that the valuation of reserves be to some extent co-optimized with the spot market in order to ensure that the opportunity cost of reserves reservation is reflected in energy prices. One such approach is often referred to as "scarcity pricing" in the US and I argue that Europe should provide guidelines on ancillary services procurement and market reforms to reflect scarcity and operational constraints in energy markets.

- *Elements facilitating the valuation of short-run ramping capability*: In the European electricity markets, which are based on the portfolio bidding, the unit commitment constraints such as the start-up costs and the minimum run-time constraints are approximated through the block bids of various forms. The simplest block bid stretches over several consecutive hours. Such block bids must be either entirely accepted or entirely rejected by the power exchange based on the average spot price over these hours. European power exchanges are currently exploring the opportunities of introducing other block products that could better reflect plant flexibility and ramping constraints (e.g. linked block bids). These products can be considered as analogous to the US approaches to value ramping capability. However, introducing complex products may be associated with significant computational challenges since these products materially increase the complexity of the market clearing algorithms.

More granular locational price signals to coordinate the multiplicity of market participants

The second area of improvement for current energy markets is to ensure that markets provide more granular price signals to avoid and manage network congestion. The current national zonal pricing approach in Europe leads in some countries to significant congestion and redispatching costs, for instance in Germany and in the UK. Going forward, I argue that some form of local price signals for flexibility services will need to emerge in order to facilitate the integration of large quantities of variable renewable generation and coordinate an efficient system operation based on a merit order of flexible resources.

Taking a step back, the laws of Kirchhoff require that electricity production and consumption need to balance in real time in each point of the network. It is therefore important that electricity prices convey locational signals to optimize the operation of networks, production and load in different nodes of the network, but also to provide incentives to locate new production assets, build new transmission lines, or to implement demand side management programs, in the most efficient way, i.e. in the way that maximizes social welfare.

Congestion management of networks is important to manage transmission constraints that may limit the flow of electricity from generators to loads in some circumstances and cause problems related to operational security (such as overloading of network elements). There are two main alternative theoretical designs:[89]

– *The zonal approach* defines limited geographical areas (zones) within which trading between generators and loads is unlimited. However, to cope with operational security constraints of the network, trading between these areas is limited by transmission capacity based on capacity calculation and allocation process. In practice a zone is characterized by one single price for the whole zone, and the cost of congestion management is in part pushed to the frontier with the neighboring price zone.

– *The nodal approach* considers all trades between generators and loads as equal in terms of using the infrastructure. The bid price and quantity of each generator and load is weighed against its influence on the physical network, leading to different prices at each node of the network.

In practice, the current electricity markets arrangements in Europe are largely based on a zonal approach, which divides the market into different price zones. Whilst historical legacy means that current zones do largely correspond to countries, there is evidence such as ENTSOE's 2018 bidding zone review to suggest that these current zones are not all optimal and do not provide the right kind of location signals for both operations and/ or investment. Smaller price zones have already been implemented in some places with significant transmission constraints, such as the Nordic countries (with market splitting) or Italy (which has different price zones), or the split of the German / Austrian bidding zone in 2018.

Going forward, I have argued in previous publications that implementing more granular locational price signals will be key in order to integrate large quantities of variable decentralised renewables (Roques et al., 2015).[90] The need for revisit the current congestion management approach is however quite differentiated across countries as the expected costs and benefits of such reforms vary largely.

Some countries such as Poland are implementing the traditional nodal approach. Another approach is emerging in a number of European countries based on the introduction of local energy markets (LEM) which could help to defining a merit order of the costs of different flexibility resources and to allocating flexibilities at the distribution grid level to reduce congestions. Transmission system operators (TSOs) could also benefit from the flexibility resource coordination service provided by these new interfaces between local and central market structures for grid-oriented purposes (e.g. reduction of congestions). These new coordinating market platforms are at the interface between local and central energy markets and will therefore raise a number of implementation challenges between these local platform operators, DSOs and TSOs.

Finally, another possible complementary approach to provide enhanced locational signals is to differentiate the network and connection charges by zone. Investment incentives to locate plants or to encourage DSM in specific locations are indeed largely shaped by the type of

[89] See ACER/CEER Annual Report on the Results of Monitoring the Internal Electricity and Natural Gas Markets in 2011 – 29 November 2012.
[90] Roques F. *et al.* (2015), IEA RETD publication, "Electricity Market Design and Renewable Energy Deployment".

network and connection charges. The two extreme approaches are deep or shallow connection charges. Shallow costs refer to the equipment needed to connect a generation plant to the nearest point of the network, whilst deep costs include shallow costs plus the costs of reinforcing the network necessary to connect that plant. The EU member states have different approaches to connecting regimes, and some countries allow renewables plant to benefit from more favorable connections charges than those applying to conventional generators.

These differences both in congestion management approaches and in network connection and possibly usage charges highlight the lack of coordinated approach toward sending appropriate locational signals to electricity market players in Europe. I therefore recommend the different possible models and approaches to provide locational signals in European markets should be evaluated with a view to identify best practices depending on the specific local challenges faced by the electricity system. Europe should foster experimentations of different types of flexibility platforms in the coming years and could eventually come up with a set of guidelines and recommendations for a more widespread roll out in the future.

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