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Implementing the National Emissions Reduction Plan (NERP): How should Ukraine's power plant park look like in 2033?

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About Low Carbon Ukraine

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Executive summary

Ukraine risks significantly falling behind on implementing the National Emission Reduction Plan (NERP), a binding obligation towards the Energy Community (EnC). A debate about a possible revision of the NERP has started in Ukraine but so far focuses on relaxing the requirements of the NERP, including the deadlines already extended especially for Ukraine. Such a course of action appears highly risky with regard to the necessary agreement of the EnC's Ministerial council. This paper aims to analyse Ukraine's obligations and options to get implementation of the NERP back on track.

Ukraine falling behind on international obligations

As a member of the EnC, Ukraine is obliged to comply with the requirements of the Large Combustion Plants Directive since 2018 and with even more stringent emission limit values in the framework of the Industrial Emissions Directive by the end of 2033. These directives define clear emission limits for SO2, Nox and dust emissions of large combustion plants, especially coal-fired thermal power plants (TPPs). Ukraine has bindingly committed itself to the EnC to a gradually implement these standards until 2033 through its NERP.

The NERP specifies, which TPPs and combined heat and power plants (CHPs) are to be retrofitted with filters, replaced by new and compliant plants, or to be decommissioned, and when. Plants to be retrofitted are subject to an aggregated emission ceiling until all are to be compliant individually by end 2033. Plants slotted for decommissioning are subject to operating hour limits of 20,000 or 40,000 operational hours until end 2023 or end 2033 respectively in separate but related opt-out lists that we include under a "wider NERP" in our analysis. However, no substantial implementation steps in Ukraine have been taken so far and the country will likely exceed its aggregated ceiling in the coming years, risking an infringement procedure to be started by the EnC.

A greener and cheaper NERP instead of postponed deadlines

To get back on track, some experts have suggested attempting to renegotiate the NERP towards extended deadlines and weaker compliance requirement. This is extremely unlikely to be accepted by the EnC as it would set a difficult precedent. Ukraine already has longer deadlines than all other EnC members. A change in Ukraine's commitments would require a corresponding proposal by the EU Commission and the agreement of the EnC Ministerial Council.

However, renegotiation of the NERP could be feasible if Ukraine instead focused on increasing the green ambition of the NERP by committing to more decommissioning rather than retrofitting of TPPs. The present NERP appears neither economically nor ecologically optimal for Ukraine. It entirely ignores existing plans to increase the share of renewable energy sources (RES), other developments (such as more sluggish demand growth than expected in 2017) and alternative options for the energy sector (such as more cost-efficient flexibility sources than TPPs). It hence foresees large-scale modernisation, retrofitting and even the replacement of 12 TPPs by new TPPs without regard to how many should operate by 2033. This could result in excessive investments into an unnecessary and outdated technology. A greener NERP could well be a cheaper NERP.

Which power plant park should the NERP aim for?

To verify this hypothesis, our analysis focuses on what power plant park would suit Ukraine's needs well in 2033. We compare several scenarios with different configurations of fossil and renewable energy sources whilst holding the capacity of nuclear power plants and CHPs constant (the latter should be subject to a separate analysis due to their dual role). These scenarios are not mathematically optimised but are intended to provide guidance that can be further refined towards a final target system for the NERP. We model the optimal dispatch of power plants using our own Optimal Dispatch Model (ODM) and annualise capital costs for necessary investments (into retrofits of TPPs, lifetime extensions for all existing power plants and construction of new power plants). This yields comparable annual total costs of producing power from a systemic, "social planner" perspective. Incentives and contracts between the individual actors within the system are deliberately ignored.

An ideal scenario will require a fossil fuel source (coal-fired TPPs or open cycle gas turbines (OCGTs)) to ensure sufficient flexibility within the system to balance demand with baseload provided by NPPs and volatile energy production by RES. While TPPs have the advantage of lower investment costs (plants already exist and only require filter retrofits and lifetime extensions) and lower fuel costs, they are not very flexible and need to operate at 70% of full capacity to be able to offer up-reserves. OCGTs need to be newly constructed and require more expensive fuel (including the political considerations on import requirements) but are a more flexible and cleaner source of power. Also, for a new investment, OCGTs are relatively capital-unintensive and able to provide useful backup capacity even in later stages of the energy transition.

Five scenarios under analysis

- **Current plan**: Large-scale retrofitting and replacement of TPPs as foreseen by the existing NERP
- **Reduced coal**: TPPs remain the fossil-fuel flexibility element of the power mix, but the number of TPPs to be retrofitted or replaced is reduced to the order actually required
- **Gas turbines**: All TPPs are retired and OCGTs are built to provide system flexibility
- **Combined**: A mix between the *reduced coal* and *gas turbines* scenario: TPPs provide semi-flexible "shoulder" generation, OCGTs are used for quick flexibility
- **Renewable+**: +40% capacity across all RES capacities compared to the other scenarios, no TPPs. OCGTs provide required flexibility in the system

Current plan is outsized, different options for a better endpoint

Our analysis shows that the *current plan* scenario is the most expensive with annual cost amounting to EUR 21.7 bn. A large number of TPPs to be retrofitted or even replaced would never actually be required. Hence, the *reduced coal scenario* would save EUR 3 bn per year by scaling down TPP retrofits to those actually useful. This alone would save EUR 14.9 bn in total investment costs compared to current plans. However, more progressive scenarios with regard to cleaner and more modern asset bases with more OCGTs are in a similar range. The *combined scenario* is cheapest at EUR 18.6 bn annual cost, but the *gas turbines scenario* is also not substantially more expensive. A yet further expansion of RES (*Renewable+*) beyond the current plans would cost EUR 0.5 bn more than the *reduced coal* scenario due to higher investment needs.

The more progressive scenarios – *combined*, *gas turbines* and *renewable+* – would leave Ukraine with a progressively more modern asset base by 2033, better geared to expected future needs and including more freshly built power plants compared to renovated vintage TPPs. CO_2 emissions would be similar at around 16 $MtCO_2$ per year in the three scenarios with substantial TPP shares in generation (*current plan*, *reduced coal* and *combined*). For relatively modest prices, further reductions of CO_2 emissions could be obtained by moving to the *gas turbines* (8.4 $MtCO_2$) or even *renewable+* (6.6 $MtCO_2$) scenarios.

Revising NERP is sensible, but only under commitment to greening rather than relaxing

Urgent action is required to bring the NERP process back on track and avoid a reputation-scarring infringement procedure. To stand any chance of success with the EnC, it only makes sense to open NERP renegotiation if firmly committed to a greener NERP with more decommissioning of TPPs compared to the present plan. Economically as well as ecologically, this is preferable for Ukraine anyway.

After ensuring this commitment, the process towards NERP revision should be carefully designed, ensuring apt involvement of national and international stakeholders and experts. Substantially, it will first involve a decision on the envisioned park of thermal units in 2033, the formulation of the NERP itself, the formal renegotiation and revision of the NERP with the EnC and then, crucially, the implementation of NERP at national scale. Action on and preparation of all these stages is required immediately but can save Ukraine from having to implement the current, oversized NERP.

Scenarios: Annual cost results and differences in capacity assumptions across scenarios

			Current plan	Reduced coal	Gas turbines	Combined	Renewable+
Capacity build-up, GW	TPP	Retrofits	15.9	6.1	0	3.6	0
		New plants	4.8	0	0	0	0
	OCGT	New plants	0	0	7.8	3.4	5.4
	RES	New plants	11.9	11.9	11.9	11.9	19.6
Annual costs, EUR bn		CAPEX	13.2	10.6	10.5	10.6	11.4
		OPEX	8.5	8	8.4	8	8
		Total	**21.7**	**18.7**	**18.9**	**18.6**	**19.4**

Source: LCU

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1 Introduction

By virtue of its membership in the Energy Community (EnC) (an energy-market international organisation on the European Union and its neighbours) Ukraine has committed itself to implement stringent emissions limits originating in the EU's Large Combustion Plant Directive (LCPD) and its successor, the Industrial Emissions Directive (IED). Ukraine is legally bound to ensure that all covered plants comply with emission limitations in the IED by 2033 and has committed itself to implement a National Emissions Reductions Plan (NERP) as a transition instrument.

However, the challenge of coming into compliance remains large. Reducing emissions levels whilst maintaining output levels of affected industries will require large capital investments. Of particular relevance is the impact for the power plant park of Ukraine. Whilst nuclear power accounts for more than half of electricity generation at present, the second largest power source are mainly coal-fired thermal power plants (TPPs). Most of these plants are old, emissions-intensive and often inadequately maintained. Necessary retrofits of filters or, where more economic, replacement of old, dirty plant with cleaner new ones require substantial capital investments and may also impact operating costs, whilst power companies' ability to invest is restricted by difficult access to finance and inadequately low power tariffs that do not even fully cover regular operating costs.

So far, progress towards implementation of the NERP has been minimal. No practical steps have been taken and compliance with limit values foreseen in the NERP were largely due to economic circumstances, not policy directed at implementation. In view of the lack of progress and massive investment challenge, a debate has started in Ukraine whether the NERP and other transition arrangements for IED implementation need to be amended and whether the deadline for full compliance with the new emission limits should be postponed.

This paper aims to clarify key elements of this debate. Firstly, we explain what legally binding obligations Ukraine is subject to with regard to the NERP/IED implementation, what it applies to and how these obligations could be adjusted in chapter 2. As we find that a postponement or relaxation of Ukraine's compliance obligations is politically unrealistic, we then turn to how the challenge can be mastered. The key issue here is that current plans foresee an indiscriminate modernisation of all TPPs, regardless of the question of how the power plant park should be configured in 2033 and what plans already exist for increasing the share of renewable energy sources (RES). If some TPPs will no longer be required in 2033, investment into compliance with the IED could potentially be significantly reduced.

We hence turn to a scenario analysis for what would constitute a desirable "end-state" of the Ukrainian power plant park in 2033. Using our optimal dispatch model (ODM) and a calculation of annual capital and operational costs, we compare different configurations of the power plant park in 2033. We explain the methodology of our analysis in chapter 3 and present our scenarios in 4. Results are presented and discussed with regard to further key policy variables such as a carbon price in chapter 5. Finally, in chapter 6 we turn to the implications this would have for a possible revision of the NERP.

2 Legal and political situation

By virtue of its membership in the EnC, Ukraine is obliged to implement the LCPD from 2018 and the IED by the end of 2033. Approved by the Cabinet of Ministers of Ukraine in 2017, the NERP acts as a transition device for compliance with the demanding requirements of the IED. However, Ukraine is currently struggling to implement the NERP and hence to make progress towards compliance with the LCPD and IED. This chapter aims at explaining Ukraine's international commitment, the state of implementation of the NERP and the question of what room for manoeuvre exists to change Ukraine's obligations in view of implementation difficulties.

2.1 International legal framework

Ukraine's obligations towards reducing emissions of its power plants originate from its membership in the EnC. The EnC is an international organisation which brings together the European Union (EU) and its neighbours to create an integrated pan-European energy market. Its treaty came into force in 2005 and the key objectives are to extend the EU internal energy market rules and principles to countries in Southeast Europe, the Black Sea region and beyond. Ukraine became contracting party of the EnC in 2011. By adopting the EnC Treaty, Ukraine made legally binding commitments to adopt core EU energy legislation, the so called "acquis communautaire". It envisages that EnC countries in general are allowed to adapt the acquis and implement amendments to keep track of EU law.[1]

Whilst the electricity, gas, energy efficiency, environment and renewable energy acquis have in the meanwhile undergone several updates, new acquis on statistics and oil emergency stocks were added in 2012. In October 2015, a new infrastructure regulation was added to the list. Decisions to adopt new acquis and amend existing legal commitments are generally taken by a majority of the votes cast of the Ministerial Council on the basis of a European Commission proposal.[2]

The LCPD[3] was adopted in 2001 and is part of the EU environmental protection acquis. The commitment contains the regulation of emissions of large combustion plants (LCPs), incl. TPP and combined heat and power plants (CHP). Plants are restricted to emitting combustion plant specific emission limit values (ELVs) for nitrogen oxides (NO_x), sulphur dioxide (SO_2) and dust (from 2018 onwards (Table 9 in Annex). The ELVs vary according to the age and capacity of the plants, as well as the type of fuel used. Importantly, and different from obligations towards reducing CO_2 emissions, ELVs are set at the level of each plant. Hence, no specific total emissions maximum is set for Ukraine, but each plant must comply with ELVs individually with no specific limit on total national emissions.

[1] The Energy Community Legal Framework, 4th edition (January 2018), Article 24 and 25

[2] https://www.energy-community.org/legal/acquis.html

[3] Directive 2001/80/EC of 23 October 2001 on the limitation of emissions of certain pollutants into the air from large combustion plants

What is a large combustion plant?

A large combustion plant (LCP) is any technical apparatus which fuels are oxidised in order to use the heat that is generated in the process. Fuels can be solid (coal, lignite, biomass, peat, coke, patent fuels, tar), liquid (oil) or gaseous (natural gas, coke oven gas, furnace gas, LPG, blast furnace gas). 50 MW thermal input capacity (MWth) is the legislative threshold to be considered a LCP. In practice, this applies to thermal power plants (TPPs) and combined heat and power plants (CHPs) as well as power generation or heating using exhaust gas from other industrial uses such as steel production. A plant can consist of only one or many individual combustion units. If there are multiple combustion units but one common stack, it is considered one large combustion unit. The LCPs have to report their data on pollutant emissions for SO_2, NOx and dust in tonnes.

Source: European Environment Agency (2018) 'Overview of EEA Reporting Requirements for Large Combustion Plants', Energy Community Environmental Task Force Meeting

On 24 November 2010, the EU adopted the IED[4]. It is now the main EU instrument regulating pollutant emissions from industrial installations. The IED has more stringent ELVs for combustion plants (Table 10 in Annex) and entered into force for EU countries on 6 January 2011. EnC countries were obliged to bring into force laws, regulations and administrative provisions necessary to comply with IED since 2013.[5] As of January 2018, existing plants have to comply with LCPD ELVs[6] while new plants built after that date already have to comply with IED ELVs. Until 2028, all plants must comply with IED ELVs[7].

Two derogation mechanisms exist that are intended to facilitate the transition of EnC member states into compliance with the LCPD and IED. On 23 October 2013, the EnC allowed contracting parties to develop National Emission Reduction Plans (NERPs).[8] A NERP functions as an implementation vehicle for the LCPD and IED ELVs with a gradual reduction of emissions for all plants until 2028. During its period of operation, the NERP system relaxes compliance requirements for plants. All plants under a NERP must comply with emissions limits for aggregated ceilings at the level of the "bubble" of participating plants instead of each plant individually having to comply with ELVs. The aggregated emission ceilings for each pollutant (SO_2, NOx, dust) are calculated based on the LCPD and IED ELVs. However, by the expiration of the NERP, all plants must then comply with ELVs individually.

Furthermore, existing plants may be exempted ("opted out") from compliance with the ELVs of the LCPD in the period 2018-2024 and from their inclusion in the NERP, provided the facility does not operate more than 20,000 hours during these years and is then retired. If, however, the plant is to operate after that deadline it would have to meet the IED ELVs.[9]

[4] Directive 2010/75/EU of 24 November 2010 on industrial emissions (integrated pollution prevention and control)

[5] D/2013/06/MC-EnC: On the implementation of Chapter III, Annex V, and Article 72(3)-(4) of Directive 2010/75/EU of the European Parliament and of the Council of 24 November 2010 on industrial emissions (integrated pollution prevention and control) and amending Article 16 and Annex II of the Energy Community Treaty)

[6] D/2013/05/MC-EnC: On the implementation of Directive 2001/80/EC of the European Parliament and of the Council of 23 October 2001 on the limitation of emissions of certain pollutants into the air from large combustion plants

[7] D/2015/06/MC-EnC: on the implementation of Chapter III, Annex V, and Article 72(3)-(4) of Directive 2010/75/EU of the European Parliament and of the Council of 24 November 2010 on industrial emissions (integrated pollution prevention and control) for existing combustion plants and amending Annex II of the Energy Community Treaty

[8] D/2013/05/MC-EnC: On the implementation of Chapter III, Annex V, and Article 72(3)-(4) of Directive 2010/75/EU of the European Parliament and of the Council of 24 November 2010 on industrial emissions (integrated pollution prevention and control) and amending Article 16 and Annex II of the Energy Community Treaty

[9] The Energy Community Legal Framework, 4th edition (January 2018), Article 4

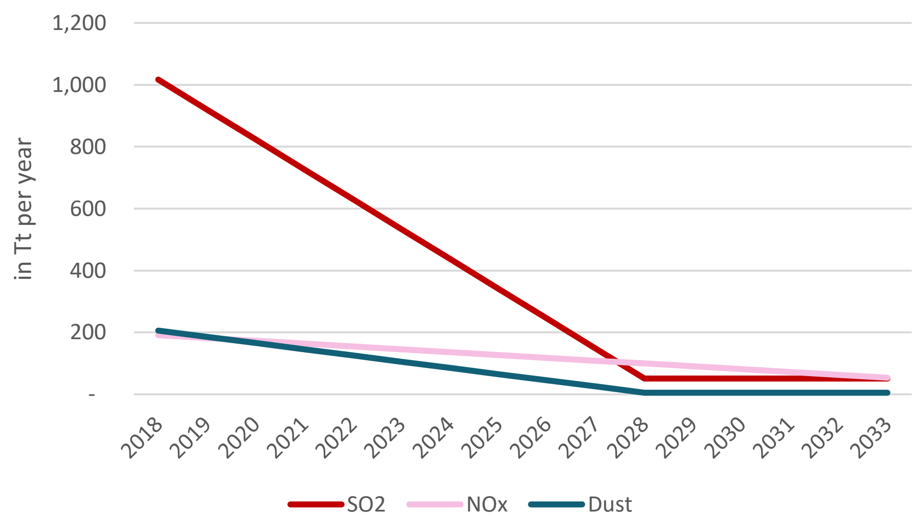
2.2 The NERP in force for Ukraine

When Ukraine joined the EnC in 2011, it committed itself to implement the plant specific ELVs of the LCPD. When it became clear in 2015 that no progress had been made to fulfil LCPD conditions, the Ukrainian government agreed with the EnC to leapfrog into compliance with these regulations and directly move to the IED ELVs for SO2 and dust by 2028 and for NOx by the end of 2033.[10] Ukraine hence has the longest implementation deadline among all EnC countries which have to comply with IED ELVs for all pollutants by 2028. Furthermore, Ukraine received a special adjustment regarding the opt out of LCPs, which, if specified, may run until the end of 2033 if they do not exceed 40,000 operating hours.

The Ukrainian Ministry of Energy drafted a NERP that was accepted by the EnC in 2017, with further changes made in 2019. The procedure for all LCPs are defined in the four annexes of the NERP. Annex I lists all 223 existing plants in Ukraine that must comply with LCPD ELVs since 2018 (Table 1). Out of these, 84 LCPs with a total capacity of 61.5 GW thermal input (GW_{th})[11] are included in the actual NERP. This includes 22 coal-fired TPPs and 62 CHPs. These plants are subject to aggregated emissions ceilings for each year (Figure 1). In these ceilings, the emissions of all plants in the NERP are pooled for the transition periods. By the end of these periods, 26 of the 84 LCPs will be retrofitted and will again individually have to comply with the ELVs. The remaining 58 plants, mostly gas-fired CHPs, will operate for a maximum of 40,000 hours and be decommissioned until the end of 2033. It is not fully clear from the existing documentation, whether or not they will be replaced by new CHPs, but their heating function would also need to be replaced. The annual aggregated ceilings will bring the entirety of plants to comply with the IED ELVs by 31 Dec 2027 for SO2 and dust and 31 Dec 2033 for NOx. The ceilings for the intermediate years are set providing a linear decrease of the ceilings.[12] In comparison to 2018 emissions levels, this will amount to reductions of emissions by:

- 95% for SO2
- 98% for dust
- 72% for NOx

Figure 1: Aggregated emission ceilings for the 84 existing large combustion plants included in the Ukrainian NERP



Source: National Emission Reduction Plan for Ukraine (08 November 2017)

[10]D/2015/07/MC-EnC: On amending Decision D/2013/05/MC-EnC of 24 October 2013 on the implementation of Directive 2001/80/EC of the European Parliament and of the Council on the limitation of emissions of certain pollutants into the air from large combustion plants and on amending Annex II of the Energy Community Treaty

[11] Gigawatts of thermal capacity, not all of which is converted into electrical energy (e.g. efficiency losses and capacity used for producing heat in CHPs

[12] If a plant drops out of NERP (e.g., due to being retired), the aggregated emissions ceilings will be reduced proportionally.

Annex III of the NERP stipulates specific retrofitting measures for 26 (45,4 GW_{th}) of the 84 plants. While almost all TPPs in the NERP are also foreseen for retrofitting measures to allow them to stay in operation beyond 2033, most CHPs are to be decommissioned until the end of 2033.

A further 16 plants are opted out of the LCPD requirements using the "limited lifetime derogation" (max 20,000 operating hours until 2024 and subsequent retirement). An extended opt-out derogation was created especially for Ukraine so that another 50 plants may be allowed to operate for not more than 40,000 hours until the end of 2033 without complying with LCPD ELVs.[13] All plants in the opt-out lists do not have to comply with the aggregated emission ceilings. The opt-out lists in Annex IV indicate that 18 GW_{th} of the total 41 GW_{th} of TPPs and CHPs to be decommissioned will be replaced by new coal-fired power plants.

Of the 223 installations covered by the LCPD, 74 already meet strict ELVs. These 74 plants are all CHPs, most of which are gas-fired or new.

Table 1: The distribution of LCPs among the Annexes of the NERP

Annexes	Description	Number of LCPs			Thermal power in GW		
		TPP	CHP	Total	TPP	CHP	Total
Annex II	All LCPs in NERP	22	62	84	42.4	22.5	64,8
incl. Annex III	*Specific retrofitting measures for LCPs in NERP*	*21*	*5*	*26*	*42.2*	*3.2*	*45.4*
Annex IV	Opt-out: 20,000 hours until 2024	3	13	16	3.7	3.4	7.1
	Opt-out: 40,000 hours until 2034	12	38	50	24.5	9.3	33.8
LCPs neither in Annex II nor in Annex IV		0	74	74	0	10.2	10.2
Annex I	All plants falling under the LCPD	37	186	223	70.5	45.4	115.9

Source: National Emission Reduction Plan for Ukraine (08 November 2017), Annexes I-IV
Note: The figures for "Number of LCPs" can differ from official figures in the NERP due to different approaches to count the LCPs in the Annexes. LCPs can consist of several power units which are either retrofitted or decommissioned. Since one LCP is counted as one, we counted a power unit as, e.g., ½, when the other power unit of the LCP is foreseen for something else. For comparison, the distribution of LCPs as given in the NERP is given in Table 12 in the Annex.

2.3 Implementation and political discussion in Ukraine

In November 2017, the Cabinet of Ministers adopted the NERP, authorising the Ministry of Energy to coordinate the implementation. In 2018, the government approved an action plan to implement NERP.[14] The action plan foresees the following main measures:

1. Establishment of an organising committee and approval of the action plan 2019-2033
2. Establishment of a temporary working group of the Ministry of Energy which shall develop a mechanism for NERP implementation
3. Together with operators: identification of the needs and problems of reconstruction, modernisation, and technical re-equipment of LCPs
4. Identification of potential financial sources

[13] D/2015/07/MC-EnC: On amending Decision D/2013/05/MC-EnC of 24 October 2013 on the implementation of Directive 2001/80/EC of the European Parliament and of the Council on the limitation of emissions of certain pollutants into the air from large combustion plants and on amending Annex II of the Energy Community Treaty

[14] Cabinet of Ministers: On approval of the action plan for 2018 for the implementation of the National Emission Reduction Plan for large combustion plants (13 June 2018) https://zakon.rada.gov.ua/laws/show/428-2018-%D1%80#Text

5. Identification of best solutions for monitoring, control and reporting
6. Financial support for monitoring, control and reporting
7. Priority identification and implementation for cooperation with international and regional organisation, foreign countries and its financial institutions that support the NERP implementation

However, since 2018, no progress has been made in implementing the action plan. In 2019, the Cabinet of Ministers of Ukraine and the EnC approved some amendments to the NERP, but these were of a mainly technical nature and had no effect on the annual emissions ceilings. In 2019, the emission ceilings of all three pollutants were met due to low heat and electricity demand.[15] In April 2021, Ukrainian operators provided emissions data for 2020 showing that they were below the aggregated emission limit values. However, this data cannot be verified and some operators reported emissions that are exactly equal to the NERP ceilings, which is technically almost impossible and hence unlikely to reflect actual emissions.

The plant operators point to high required investment as the main problem implementing the necessary retrofitting measures. Frequent regulatory changes lead to high risk premiums and capital costs. According to the plant operators, it is therefore not possible to accumulate the necessary capital. In September 2020, during a discussion with the EnC Secretariat, the Ministry of Energy asked the EnC to postpone the implementation of the NERP for another 5 years.[16] Currently, Ukraine is updating the facilities list (opt-out-list), developing financing mechanisms for the necessary power plant upgrades and negotiating with international partners and market participants.

In August 2020, the Ministry of Energy created an advisory group under the newly established expert council (established in June 2020) composed of representatives of the Ministry of Energy and Ministry of Environment, plant owners and Ukrenergo to further asses the state of affairs. On 02 October 2020, the advisory group recommended the following measures:[17]

- Postpone implementation date to 2022 or 2025 and postpone the deadlines for the implementation of measures from 2033 to 2038 or 2043
- Units that are retrofitted to use G-grade coal before 2020 should not be decommissioned after 20,000/40,000 hours but included into Annex II and Annex III
- Create a mechanism for exchanging working hours among plants
- Remove mandatory types of emission reduction technologies in Annex III
- Shift the costs of the measures for private TPPs and CHPs to the state

Debate about whether the implementation should be delayed is ongoing. Representatives of the EU, environmental NGOs and opposition parties have been critical of the plans, whereas it appears to have the support of plant owners. Another topic of debate is whether, during the implementation of the NERP, electricity supply would be ensured at all times during necessary outages of plants undergoing retrofitting. The central question in the debate is, how the investment costs for necessary modernisations or replacements can be borne and by whom.

Any postponement of Ukraine's NERP would require the agreement of the EnC Ministerial Council including EU member states. Politically, such an agreement is considered unlikely at this stage due to the lack of any progress in implementation in Ukraine whilst other EnC countries are also struggling but making progress on implementation of the directives. Non-compliance with the obligations could result in an infringement procedure as per the EnC's rules and would damage Ukraine's image as committed to further integration with the EU and its surrounding institutions and rules.

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[15] Energy Community (2020) 'Ukraine: Annual Implementation Report'

[16] http://mpe.kmu.gov.ua/minugol/control/publish/article?art_id=245470792

[17] https://energytransition.in.ua/service/orhanizatoram-ta-uchasnykam-komitets-kykh-slukhan-na-temu-realizatsiia-zakhodiv-z-ekolohizatsii-velykykh-spaliuval-nykh-ustanovok-ta-skorochennia-vykydiv-zabrudniuiuchykh-rechovyn-shliakh-do-chystoho/

2.4 Compatibility with other plans for the Energy sector

The NERP submitted by Ukraine appears to be quite unrelated to other climate-related obligations and plans of Ukraine. It has a clear focus on retrofitting or replacing old coal-fired power plants and essentially implies that the share of electricity generated from coal would remain constant. This contradicts the country's decarbonisation efforts and plans. For example, Ukraine might possibly raise its climate ambition with the upcoming update of its Nationally Determined Contributions (NDC2). The current draft aims at ambitious economy wide greenhouse gas (GHG) emission reductions by at least 65% below the 1990 level by 2030 (Ministry of Environmental Protection and Natural Resources 2021). The ambition of reducing GHG emissions also raises the expectations of sectoral transformation and implementing the NDCs into the different sectors of the Ukrainian economy. In 2018, the electricity and heat sector caused 99 MtCO2eq of GHG emissions (29% of total GHG emissions). Until 2030, emissions in the electricity and heat sector could decline to 61 MtCO2eq.[18]

In order to achieve this emission reduction a considerable amount of renewables must be deployed in the electricity sector. According to the NDC2, the RES share in electricity generation needed to achieve the -65% target amounts to approx. 30% (2020: 11%). Similar RES targets are stated in Ukraine's Energy Strategy until 2035, which targets a ">25%" renewable share in electricity generation and a 25% RES share in total primary energy supply for 2035. This means that significantly more than 25% RES share in electricity generation is needed to actually achieve 25% in total primary energy supply. The surge in renewable capacity deployment implied by these two Ukrainian strategies will have implications for the economics of the existing power plants: Once new solar and wind parks start generating electricity without incurring fuel cost, there will be more and more hours during which renewables push the more expensive baseload coal plants out of the electricity market. Nuclear, which scores better in terms of variable cost and emissions than coal, will be less affected by higher RES generation in a competitive market. Reduced full load hours, increased cycling requirements and thus lower efficiency will seriously affect the profitability of legacy coal plants, potentially making the operation of a large part of Ukraine's coal plant fleet unprofitable. The fact that plant operators will have fewer full load hours to recover their expenses on NERP compliance adds to the dire economic outlook of coal in a world with increasing RES shares.

Instead of baseload coal power plants, new and flexible peaking power plants as well as other flexibility options will be needed to balance the intermittent availability of wind and solar electricity. Increasing RES penetration in Ukraine means that traditional baseload generation simply must give way for new peak load generation and storage.

Ukraine should hence ensure that NERP-related retrofitting investments into coal plants do not turn out to be stranded investments. The TPP fleet should only be modernised as far as it is needed to ensure security of electricity supply – thermal units that are not needed from a system adequacy point of view should not be modernised to comply with NERP requirements in the first place and decommissioned instead. Replacing the decommissioned coal plants by flexible peaking plants and other flexibility options before ensures security of supply by 2034 and ensures a sustainable RES deployment after 2034.

Generation adequacy studies for Ukraine that take into account the country's political electricity targets are therefore needed. Once those studies become available, the list of power plants falling under the NERP should be thoroughly reviewed. The paper at hand tries to provide an input into the current Ukrainian adequacy discussion by estimating how much legacy baseload as well as new peak load capacity is actually needed if Ukraine were to achieve its updated NDC.

[18] The Ministry of Environmental Protection and Natural Resources (2021) 'Analytical Review of the Second National Determined Contribution of Ukraine to the Paris Agreement', https://mepr.gov.ua/news/37144.html?fbclid=IwAR2GuJOp2QgL7yFgknw9C8dciMbVmp_IyJMoFdjTDld4N6Tq2ceX2xaiwy0

The Ministry of Energy is currently working on new plans for a strategy for the coal industry and the transformation of coal regions. So far, no official date for phasing out coal has been announced. DTEK, however, is planning to end coal-fired power generation by 2040.

2.5 Upshot

Both the implementation and the design of the Ukrainian NERP appear deficient. Implementation of the NERP will require regulatory measures and perhaps also financial mechanisms. Regulation must set binding emissions limits that plant operators must comply with by certain deadlines. If necessary, financial mechanisms must ensure that incentives and capabilities of operators are aligned with the NERP.

Before implementation is attempted, there is the even more pressing need to ensure that the actual plan to be implemented – what TPPs and CHPs are modernised under the NERP and which ones are to be retired and potentially replaced – takes the entire context of Ukraine's energy and climate policy into account. The current plans foresee a large-scale modernisation and retrofitting effort on the country's coal power plants, which will be both highly cost-intensive and incompatible with other plans that foresee a higher share of renewable energy in the country's electricity generation. This may lead to high and unnecessary costs for modernisations of coal power plants that will actually not be necessary by the end of the transition period in 2033.

At the same time, attempting to postpone the implementation deadlines and to soften NERP requirements as foreseen by the advisory group under the expert council of the Ministry of Energy is very unlikely to be accepted by the EnC. Continuing on the present course, Ukraine would risk reputation harm and a confrontation, possibly including an infringement procedure with the EnC. Hence, **efforts on NERP renegotiation should focus on changing the NERP and related obligations in a way that better reflects Ukraine's future energy needs, is more climate-friendly and hence more likely to find EnC support.**

3 Objective and methodology of analysis

3.1 Policy challenge

Ukraine needs to reconcile its obligations with the EnC regarding emissions of LCPs with its other energy policy commitments and the objective of affordable power generation. The LCPD/IED requirements itself imply significant reductions of SO_2, NO_x and dust emissions, which require a large share of power plants to be either retrofitted or replaced by less polluting technologies. As a large share of the existing power plants are old and often worn out due to inadequate maintenance and modernisation, investment costs are likely to be high, as highlighted by the recent study of the National Academy of Sciences (2020) finding a total investment need of EUR 4.1 bn to fulfil the NERP.

The pressing question is whether the current NERP is actually optimal, especially given Ukraine's existing climate obligations and intentions to increase the role of renewables in the power mix. While the current NERP foresees the modernisation or replacement (by modern power plants, but still using the same fuels) of all existing units, it is questionable whether this makes sense. Quite probably, the NERP should also take into account that a future power plant park of Ukraine requires fewer fossil, especially coal-fired power plants.

The aim of our analysis in the following is hence just that: To find out, how many of the existing LCPs will still be required by 2033 in a least-cost power-generating mix consistent with Ukraine's RES deployment goals and should hence be modernised or replaced in the context of a revised NERP. As the NERP is a transition device, the endpoint – the power generation mix in 2033 – needs to be set properly before a sensible transition strategy – the NERP – can be developed. If indeed, as we assume, less coal-fired TPPs will be required by 2033 than foreseen in the current NERP, the NERP could be changed in a way that emphasises more decommissioning of TPPs without replacement. While any revision of the NERP would need to the agreement of the EnC Ministerial Council, it is much more likely if the revision is emphasising more environmental ambition rather than a postponement of deadlines.

3.2 General approach

We proceed by analysing power production in Ukraine by 2033 in different scenarios. We focus on 2033 as this is the year, by which the transition period of the NERP ends and all LCPs must comply with the ELVs of the IED. All scenarios are to be compliant with the IED ELVs and hence include the costs of emission-reducing retrofits or replacements of existing LCP. Furthermore, the calculation for 2033 is more than the spotlight on just one year. We calculate the costs of power production for a "steady-state", which could persist for the coming years. This implies that we assume sufficient maintenance and modernisation expenditures for all plants to allow them to operate indefinitely[19] and annualise the capital costs of the required new constructions and retrofits. Prices are given at 2021 levels in Euro. For technology-specific costs subject to cost-degressions, we took forecasts for 2033 levels (operational costs) and 2026 (new plants, lifetime extensions and retrofits)[20] and deflated them to current price levels.

Scenarios are differentiated by the installed capacities of power generation from different fuel sources, with the variation being mainly in the fossil fuel sources and, in some scenarios, in the renewable energy sources. We then compare these scenarios by calculating the *total cost of power generation* for the scenarios from its different components:

- CAPEX (capital expenditures)
    - Retrofits of emission-reducing filters etc.
    - New plants
    - Upgrades (e.g. lifetime extension) of existing plants
- OPEX (operational costs)
    - Fuel costs
    - Fixed and variable annual operations and maintenance
    - Carbon prices (but only as a robustness check)

As we do not consider issues of power plant and demand locations here, we do not consider grid or other costs but solely model the costs of the different power plants. We model fuel costs and other variable costs depending on usage of installed capacity by using our Optimal Dispatch Model (ODM, see 3.3), which also takes into account grid constraints on the transmission level. This yields an optimal usage of installed capacity and hence minimises the total variable cost of power generation. All one-off investment costs are annualised with reasonable assumptions on depreciation periods of the investments and interest rates, in tune with the "steady state" approach of requiring sufficient investment into modernisations to uphold this system of power generation over a period of years.

Importantly, we model the costs of the system and its use from the perspective of a "social planner". This means that we ignore different incentives faced by the various agents in a system and model the costs at social level of a system functioning optimally (at optimal dispatch = minimum fuel costs for any given configuration of installed capacity and a given total energy demand). Hence, we abstract from the subtleties of the Ukrainian energy sector – such as the issues created by subsidised energy prices / below-cost tariffs paid to producers – as these issues effectively lead to inefficiencies of the sector and increased costs and should hence be resolved independently of the object of our analysis. The only slight deviation from the social planner approach is the inclusion of carbon pricing in some robustness checks. If considered strictly as a nationally imposed tax, these should not be included in such an analysis, but if seen as the cost of an externality, they should be included.

Finally, our analysis is intended to spur debate on the optimal end-point of the NERP rather than fix the optimal endpoint. As we understand, the analysis is sensitive to assumptions. We try to provide ourselves some robustness checks of crucial assumptions – such as different capital costs for technologies, depreciation periods, interest rates and carbon prices – but want to encourage readers and stakeholders to challenge our

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[19] This is a simplification of our theoretical construct. In practice, we assume that all existing plants and especially all existing TPPs that were slotted for retrofitting in the NERP can be sufficiently modernised to serve past 2033.

[20] In order to account for these costs having to be incurred between today and 2033 for the universe of power plants, hence 2026 technology costs are the average (expected) costs of these investments.

assumptions and enter into discussion. We therefore will publish the tables on which our calculations are based to allow replication and modification of our calculations.

3.3 The Optimal Dispatch Model

We utilize LCU`s Optimal Dispatch Model (ODM V1.5) to derive the minimum variable cost usage of each scenario (configuration of installed capacities). The model allows for testing whether a specific power plant park enables meeting electricity demands and if so, how the economic optimal utilization of generation capacities looks like. The model runs on hourly time resolution, which allows to consider hourly fluctuations in renewable electricity generation and demand variations. The Ukrainian electricity system is modelled with 6 TSO regions. To each node, existing power plants are associated and described by their plant characteristics. The regions are connected through the current transmission grid.

The model then determines the optimal hourly electricity generation by decisions on the use of available electricity sources while considering capacity-specific technological constraints. Such constraints comprise resource availability (e.g. water discharge, windspeed or solar radiation), ramping capabilities and minimal required run times.

We follow a unit commitment model approach for TPP and NPP generation capacities. The model determines whether one specific unit is either on or off and whether it is in start-up or shut-down mode. Unit-specific technological characteristics then determine the electricity generation – as well as reserve provision – depending on the hourly specific unit status.

Hourly demand as well as wind and solar trajectories are based on historical observations in 2019. For the determination of big hydro generation potentials, we use weekly aggregated historical figures.

Additionally, some specific assumptions are made for individual technologies:

- **Nuclear power plants (NPPs)** generate base load. Historical figures indicate that the variability (hourly adaptation) of Ukrainian NPP generation is low. Even if technologically possible, we follow this and allow for only one unit commitment decision per week for these plants. Following this, each NPP unit is either in on- or off-mode for 168 continuous hours. The maximum generation per hour is defined with 12.4 GW which considers an average maintenance time of one moth per unit.
- **Combined heat and power plant (CHP)** generation is not modelled explicitly to reflect their role as providing heat as well as power. The hourly electricity generation contribution of these plants taken to be exogenously given (determined by the need of CHPs to provide heat) and based on extrapolated 2019 hourly generation. We implicitly hence assume that the 58 CHPs to be decommissioned according to existing plans (see 2.2) will be replaced by new CHPs.
- Although ODM allows for considering **imports** and **exports**, this option is not used here to ensure that the power generation scenarios are feasible (can satisfy demand at all times) without overestimating flexibility.

3.4 Main assumptions

As we are modelling costs of power generation, the most important assumptions in our calculations are those related to the different, technology-specific costs. For the fuel costs technology-specific capital costs and non-fuel operations and maintenance (O&M) costs are taken from the "Power generation technology assumptions" of the European Commission's Joint Research Centre[21]. Costs for retrofits are from a recent paper based on Polish experience[22] with retrofitting LCPs to comply with ELVs. For necessary lifetime-enhancements to allow continued operation of existing, old TPPs with fully depreciated original capital, we assume that investments

[21] EUC JRC (2019) 'Power generation technology assumptions, POTEnCIA Central-2018 scenario', https://data.jrc.ec.europa.eu/dataset/3182c195-a1fc-46cf-8e7d-44063d9483d8

[22] Badyda et al. (2016) 'An attempt to estimate the costs of implementing BAT conclusions for large combustion plants (Próba oszacowania kosztów wdrożenia konkluzji BAT dla dużych źródeł spalania'), Nierówności Społeczne a Wzrost Gospodarczy, nr 46 (2/2016)

amounting to 25% of the original investment (for building a new plant) are required for each depreciation period.

Table 2: Technology cost assumptions

Technology	New plants, in EUR/kW	Lifetime extension, in EUR/kW	Fix O&M, in EUR/kW	Variable O&M, in EUR/MWh	Fuel, EUR per MWh
TPP coal	1,759	440	29	2.6	15
CHP coal	2,198	549	35	3.3	15
CHP gas	1,415	354	26	4.1	42
Nuclear	5,646	1,411	113	9.3	7
OCGT	613	153	11	2.7	42
Wind	1,115	279	23	0.5	0
Solar	674	168	10	0.1	0
Biogas	4,256	1,064	99	8.0	20
Big hydro	3,429	857	23	0.9	0
Run-of-River	2,601	650	23	0.9	0
Pump storage	4,436	1,109	44	-	0

Source: EUC JRC (2019) 'Power generation technology assumptions, POTEnCIA Central-2018 scenario'

Note: In our calculation, only costs for generating electricity are taken into account. For the new plants and lifetime extension costs, we assume the cost level in 2026, while for the fixed and variable O&M cost levels we assume 2033. All prices are deflated to the price level in 2021.

Table 3: Retrofit cost assumptions

Technology	Capex, in EUR per MWel	Opex, in EUR per MWel
Dust technology	59,734	448
SO2 technology	97,067	4,107
NOx technology	59,734	299
Smart controls, adjustable drives and emissions monitoring	11,200	373

Source: Badyda et al. (2016) 'An attempt to estimate the costs of implementing BAT conclusions for large combustion plants (Próba oszacowania kosztów wdrożenia konkluzji BAT dla dużych źródeł spalania'), Nierówności Społeczne a Wzrost Gospodarczy, nr 46 (2/2016)

Note: All prices are deflated to the price level in 2021. The exchange rate between the euro and the zloty in 2016 was EUR 1 = Zloty 4.36.

For the required retrofits and replacements, we calculate costs at plant-level by using the annexes of the existing NERP, where it is specified which LCPs would receive which retrofits and which should be replaced by new plants. We do not consider alternative balancing between retrofitting and replacing of TPPs with the same technology, but take the differentiation between retrofitting and replacing at face value from the NERP. In scenarios differing from the NERP, some of these plants will simply not be required at all.

An important assumption concerns depreciation periods. We assume that new plants will be depreciated over 25 years whereas lifetime enhancements and retrofits are depreciated over 10 years. We understand depreciation in the economic sense (expected lifetime of the investment, before significant additional investment over and above regular annual maintenance is required to replace/enhance the lifetime of the asset) and believe that this quite accurately reflects the expected lifespans of the assets in question. However, as the cost of capital (interest rate) in Ukraine is high (we calculate with an assumption of 15% real interest rate), differences in depreciation periods matter less for annual capital costs than they would do in countries with lower cost of capital.

Our assumption of total annual aggregated net electricity demand in 2033 for all scenarios is 140 TWh. This assumption derives from Ukrenergo adequacy report 2020[23] and own analysis of further overall energy demand in Ukraine. In order to account for self-consumption of power plants and grid losses, we arrive at a required gross electricity generation of 170 TWh per year, which has to be met by the power plant park.

Furthermore, each scenario is calculated to include a sufficient planning reserve margin of 20% as well as an operational reserve. For the latter, we follow Ukrenergo's reserve requirements and define that in each hour 2.1 GW of up-reserves and approx. 1GW of down-reserves have to be available. These are assumed to be in the same technologies that provide the flexible power generation in each scenario.

4 Scenario design and optimal dispatch

In this chapter, we first describe shared characteristics of all scenarios and then sequentially present our five scenarios. Each scenario is characterised by a different setup of installed capacities especially in the fossil power sources, and the resulting usage of the installed power generation capacity. Our scenario design was a sequential process, starting with the *current plan* scenario. Each successive scenario is then based on addressing weaknesses identified through analysing the optimal dispatch of the installed power generation capacity.

4.1 Main characteristics of scenarios

We consider five main scenarios for the setup of power generation in Ukraine. These scenarios differ mainly in the fossil fuel component of power generation. Four of these scenarios are emphasising specific energy sources, whereas the *combined* scenario aims to show the benefits of a more nuanced approach when weighing coal vs. open-cycle gas turbines (OCGT), a type of gas turbine characterised by relatively low capital costs and best suited to providing flexible generation capacity used mainly to balance demand with when other energy sources such as RES are not providing power. All scenarios, except the *current plan* scenario have been calibrated to provide sufficient, but not outsized capacity, satisfying total energy demand as well as providing the required reserve margin.

An important caveat about our scenario design is that these scenarios each are not entirely "internally" optimised with regard to the cost-minimising configuration of actual plants within the total installed capacity in each technology. To operate the ODM, it is necessary to assume an actual configuration of specific plants to run the model and derive variable costs for each scenario. This could not be done here in an exhaustive manner, hence each scenario could probably be optimised for a better configuration of plants (reducing variable costs) and perhaps even reducing the total required capacity including the reserve margin (reducing fixed costs). However, this optimisation potential is likely to be similar across all scenarios and should hence not substantially affect our main results, which concern the cost differentials between the scenarios.

Among all scenarios, we hold constant the capacity of NPPs at the level of today. There are no political plans for ending the use of nuclear power in Ukraine and an expansion appears unlikely due to extreme capital costs and incompatibility with the plans of expanding the RES share in electricity generation. We also hold constant installed capacities of CHP, big hydroelectric plants and run-of-river plants as well as pump storage (PSP) capacities. Although CHPs are falling under the EnC obligations in question, due to their dual role, we do not include them as a variable in our analysis – if CHPs are found to be unnecessary for optimal power generation, they may still be required for heat provision. We therefore explicitly rule them out of our analysis and keep CHP capacity constant over all scenarios, assuming full-scale modernisation or replacements of CHPs.

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[23] Ukrenergo (2020) 'Adequacy Report 2020' https://ua.energy/wp-content/uploads/2020/12/Proyekt-zvitu-z-otsinky-vidpovidnosti-dostatnosti-generuyuchyh-potuzhnostej-2020.pdf

For RES, we assume the same level of installed capacity (biogas, wind, solar) in most scenarios, following Ukraine's official plans set forth in the Energy Strategy until 2035[24]. Only in the *renewable+* scenario, we consider a larger deployment of RES.

Table 4: Installed capacities (GW) in each scenario

	2020	Current plan	Reduced coal	Gas turbines	Combined	Renewable+
NPP	13.8	13.8	13.8	13.8	13.8	13.8
TPP	22.0	22.0	8.0	0	4.3	0
OCGT	0	0	0	7.8	3.4	5.4
Biogas / biomass	0.1	1.0	1.0	1.0	1.0	1.4
Wind	1.3	6.7	6.7	6.7	6.7	9.4
Solar	5.9	11.4	11.4	11.4	11.4	16.0
Big Hydro	4.6	4.6	4.6	4.6	4.6	4.6
RoR	0.1	0.1	0.1	0.1	0.1	0.1
CHP	4.1	4.1	4.1	4.1	4.1	4.1
Pumped _storage (generation)	1.8	3.4	3.4	3.4	3.4	3.4

Source: Ukrenergo, NERP, LCU

Our scenarios are characterised as follows:

- **Current plan**: Large-scale modernisation, retrofitting and replacement of coal-fired TPPs as foreseen by the existing NERP (see 2.2).
- **Reduced coal**: Power from TPPs remains the central fossil and flexibility-providing element of the power mix, but the number of TPPs to be retrofitted/upgraded or replaced by new TPPs is reduced compared to the *current plan* scenario
- **Gas turbines:** All TPPs are retired and OCGTs are used as the fossil fuel element of the generation mix
- **Combined:** A mix between the *reduced coal* and *gas turbines* scenario with a mix of TPPs and OCGTs providing the fossil fuel component of the system
- **Renewable+:** All TPPs are retired, RES are built up more (+40% capacity across all RES capacities) and OCGTs provide required flexibility in the system

4.2 Optimal dispatch

Table 5 provides actual electricity generation in 2020 and the results of our Optimal Dispatch Model (ODM) for each of the scenarios that will be referred to continuously in the following sections. One important insight is already to be had immediately: All optimal dispatch scenarios assume a much smaller generation by TPPs and more by NPPs.[25] This indicates firstly a lack of optimality of the current dispatch (probably, NPPs could provide more baseload while TPPs and hydro power would still be able to provide sufficient flexibility to balance supply and demand at every moment). Secondly, all future scenarios are likely to result in much reduced CO_2 emissions as the share of the carbon-intensive TPPs in the energy mix will decline substantially.

[24] Ukrenergo (2020) 'Adequacy Report 2020' https://ua.energy/wp-content/uploads/2020/12/Proyekt-zvitu-z-otsinky-vidpovidnosti-dostatnosti-generuyuchyh-potuzhnostej-2020.pdf

[25] In our LCU analysis 'Was the dispatch of power plants in May 2020 optimal?' from August 2020, we already stated that compared to the optimal dispatch, actual nuclear load end of May was 15% too low. This resulted in increased CO_2 emissions by 250,000 t in only one week and increased operational cost by about UAH 150 m, i.e., 10% of operation cost. https://www.lowcarbonukraine.com/en/npp-analysis-may-2020/

Table 5: Total electricity production (yearly) by technology, TWh

	2020	Current plan	Reduced coal	Gas turbines	Combined	Renewable+
Nuclear	76.2	101.5	101.5	104.5	100.7	99.2
TPPs	39.5	12.8	12.8	-	12.3	-
OCGT	0	-	-	9.8	0.5	6.2
Biogas	~0	3.7	3.7	4.0	4.1	4.2
Wind	8.1	19.4	19.4	19.3	19.8	25.5
Solar		14.1	14.1	13.6	14.2	16.6
Big hydro	6.0	9.8	9.8	9.8	9.9	9.8
Run of River		1.0	1.0	1.0	1.0	1.0
CHP	14.5	9.6	9.6	9.6	9.7	9.6
Total	145.9	171.9	171.9	171.7	172.1	172.2

Source: Ukrenergo, LCU

Note: Total electricity production differs among scenarios due to different uptake into storage.

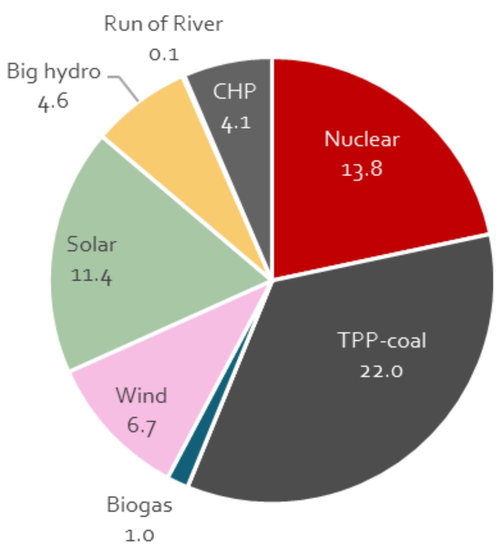
4.3 Scenario 1: Current plan

The current NERP foresees essentially the modernisation of the entire current park of TPPs and CHPs without substantial changes in technology: Coal power plants are to be retrofitted or to be replaced by new coal plants. In effect, this implies for TPPs (as CHPs are not the object of analysis for this paper) that of the existing 37 TPPs (counted as LCPs) falling under the LCPD/IED, 21 (those in Annex III of the NERP) are to be retrofitted with filter technologies whilst the other 16 older plants are to be replaced with new coal power plants, already built to ensure compliance with the respective ELVs. Together with the plans for increasing RES capacity in the system, this scenario would imply a total installed capacity of 63.7 GW (not including pump storage plants) out of which TPPs would make up 22.0 GW (34.5%).

Our ODM modelling indicates that this plan is entirely outsized with regard to coal-fired TPPs. Of the 37 TPPs, 22 would not be used at all or only for extremely low shares of their capacity. Out of 192 TWh of maximal generation capacity of the installed TPPs, only 13 TWh of generation would be required. This is largely due to the availability of power from NPPs and RES, which both produce power at lower marginal costs and hence have priority in dispatch.

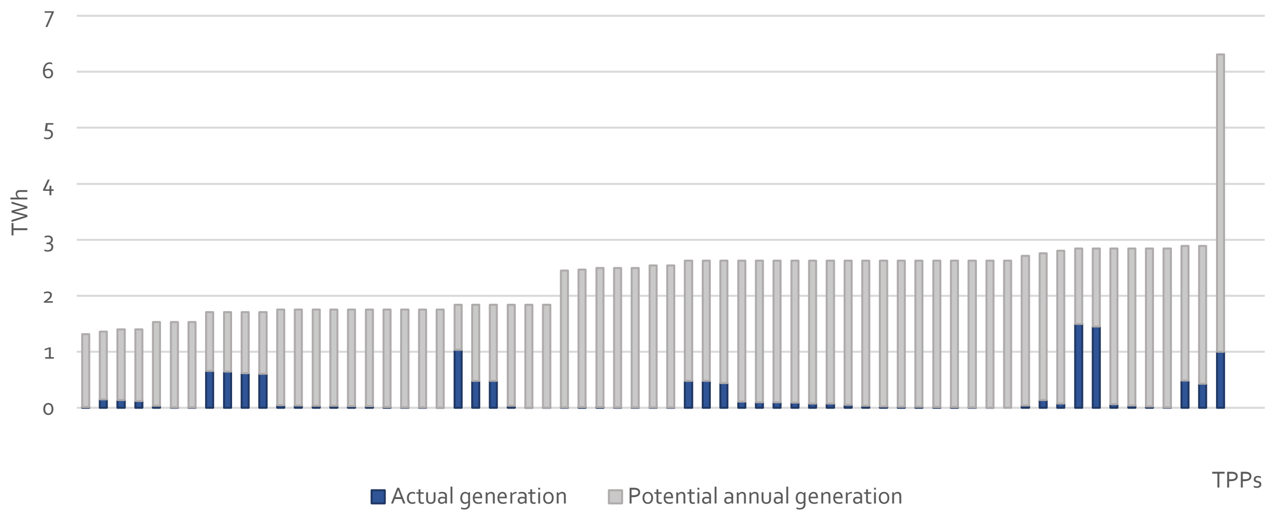
It appears that indeed, the current NERP is outsized with regard TPPs. Large investment would be wasted if entirely superfluous TPPs are modernised or even replaced by new TPPs. The main constraint is that sufficient flexibility reserves must be available to cover periods in which high demand coincides with low supply from RES due to weather factors.

Figure 2: Installed capacity in the *current plan* scenario, GW



Source: LCU

Figure 3: Actual and potential annual power generation of TPP units in *current plan* scenario

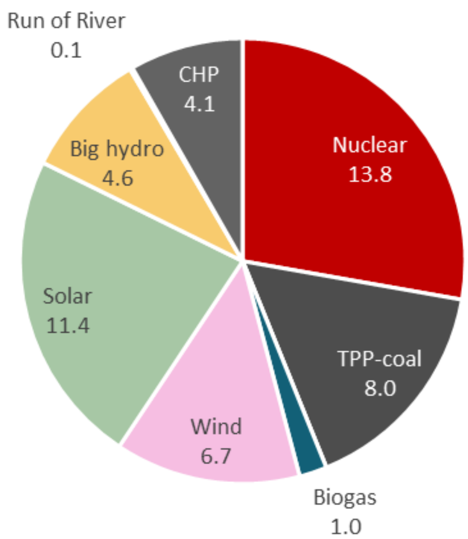


Source: LCU
Note: The bar chart only illustrates 17 GW out of a total of 22GW.

4.4 Scenario 2: Reduced coal

In this scenario, we adjusted the capacity of TPPs – hence, the number of TPP units to be retrofitted or replaced to satisfy ELVs – according to the ODM results from the previous scenario. Compared to 21 TPPs (counted as LCPs) to be retrofitted and 16 TPPs replaced by new units, this scenario only requires the retrofit of 13 TPPs (compared to 16 TPPs foreseen for retrofitting in the NERP with the "last" of the TPPs only at 60% of its capacity, hence only requiring retrofitting some of its blocks) and no replacements of any other TPPs. By reducing the installed capacity of TPPs from 17.2 GW in the *current plan* scenario to 8 GW, TPPs account for only 16.1% of the total 49.8 GW of installed capacity.

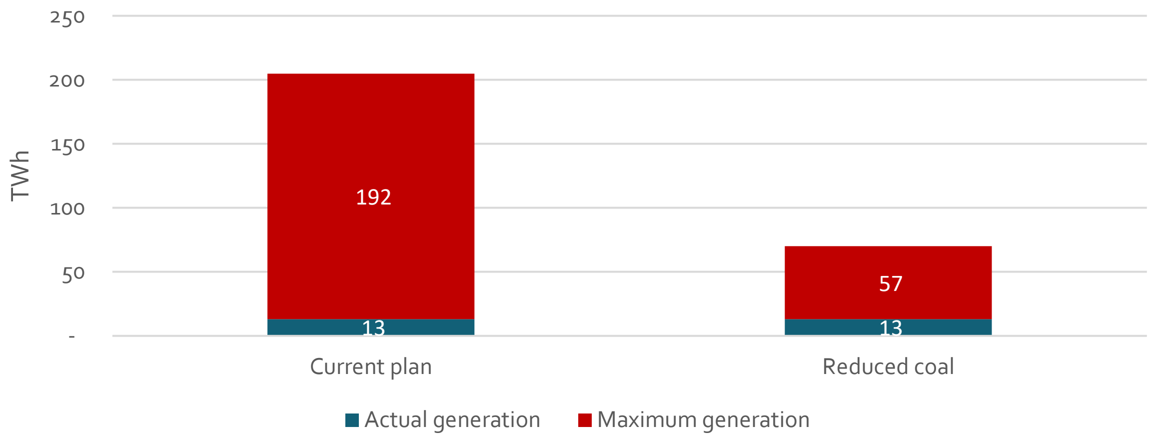
Figure 4: Installed capacity in the *reduced coal* scenario, GW



Source: LCU

This scenario has cut down the number of TPPs to be modernised to those TPPs that are actually used in our ODM modelling plus a sufficient reserve margin as described above. Hence, feasibility of the system is ensured. In total, annual generation capacity has been cut down from 192 to 70 TWh out of which an unchanged 13 TWh are actually required. Total utilisation of annual generation capacity has been increased from 6.7% but remains relatively low at 18.2%.

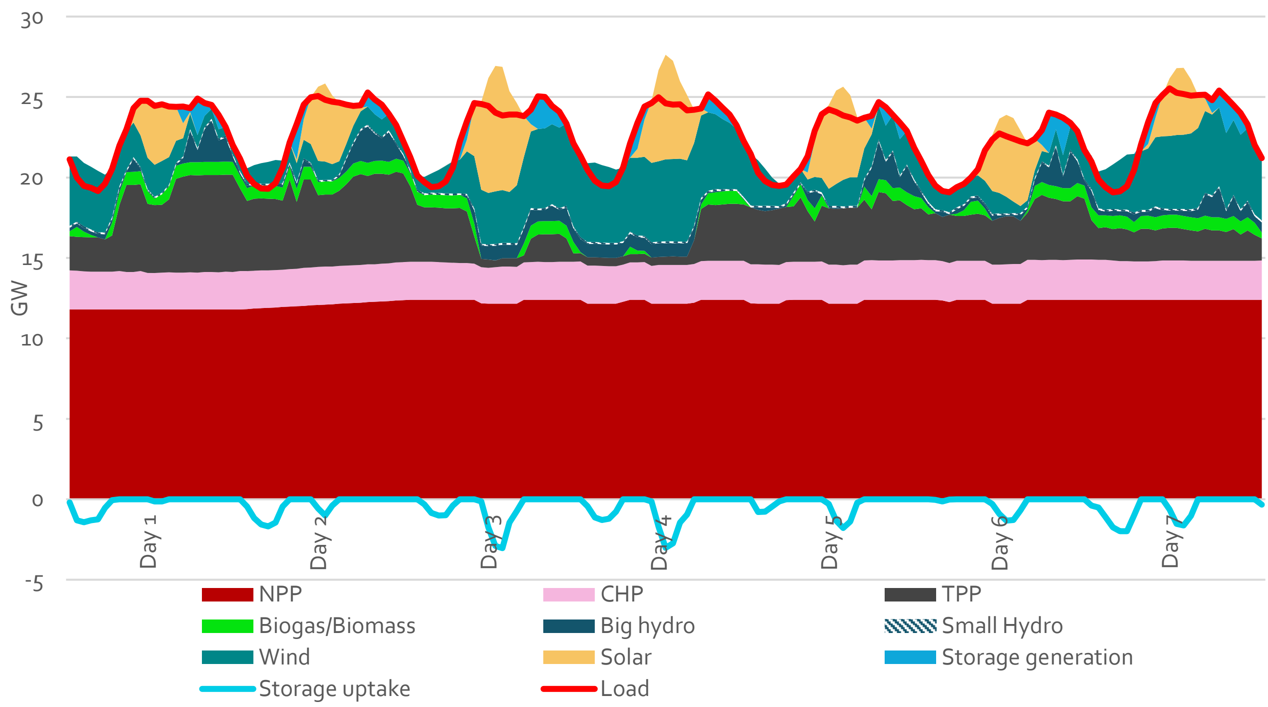
Figure 5: Actual and potential annual generation of TPPs: *current plan* vs. *reduced coal* scenarios



Source: LCU

This leads to our main concern with this configuration: Using coal-fired TPPs as the only flexible fossil fuel source of power in the generation mix is probably sub-optimal. Due to the lack of flexibility of NPPs, normal intra-day demand patterns and the volatility of generation from wind and solar power, which account for a substantial share (18.3 GW) of capacity, need to be balanced by flexible power sources. Hydroelectric and Biomass power plants as well as pump-storage capacities cannot fully provide this flexibility, hence fossil-fuel power sources are required to act as a flexible source of power.

Figure 6: Power generation by source for one week in winter, *reduced coal* scenario



Source: LCU

Note: Week 5 of the year modelled in ODM was used for all such charts to ensure comparability. The ODM for the reduced coal is practically equivalent with the current plan scenario.

In this scenario, TPPs act as this source of flexibility, which necessitates two things:

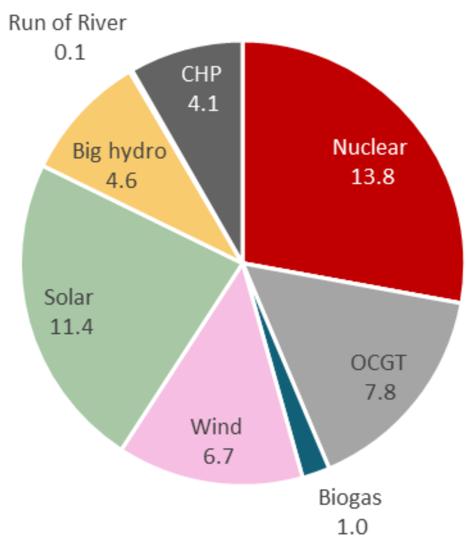
1) A relatively low utilisation of total generation capacity over the course of the year, as sufficient spare capacity must exist at any moment of time. This is unavoidable and would be the same with any other source of flexibility, it is only desirable that the fixed costs of such flexible power sources are as low as possible (which is likely the case with existing TPPs that just require lifetime-extending investments and retrofits of filters).

2) Due to technological constraints, Ukrainian TPPs need to run at a minimum load of 65-70% of a unit's capacity in order to provide flexibility by quickly ramping up (increasing power output) when required. (In most other countries with newer TPP fleets, this minimum load is at around 40%[26]). This creates a problem by potentially driving cheaper nuclear power out of the system to have sufficiently many TPPs running to provide flexibility. Compared to their maximum annual generation capacity of around 108 TWh (considering one month of maintenance shut-down for each unit), NPPs only provide 101 TWh of power. If this is indeed due to the need for TPP flexibility, it is sub-optimal. Ideally, NPPs and RES should both run at capacity (to reflect their low marginal costs of producing power) and fossil-fuelled power plants should only run to cover any unmet demand.

4.5 Scenario 3: Gas turbines

To reflect sub-optimality of TPPs as providers of flexibility in the system, we first designed this scenario, in which open-cycle gas turbines (OCGTs) – installed at a similar capacity as TPPs in the previous scenario –take up the role of providing flexibility in the power generating mix. OCGTs are characterised by relatively low investment costs, good abilities to provide flexibility in a power generating mix (fast ramping up and down without requiring baseload operation) but have relatively high fuel costs. They are hence best put in a role where they only provide flexibility, matching power demand with production from volatile RES, but do not need to run constantly in a baseload function.

Figure 7: Installed capacity in the *gas turbines* scenario, GW



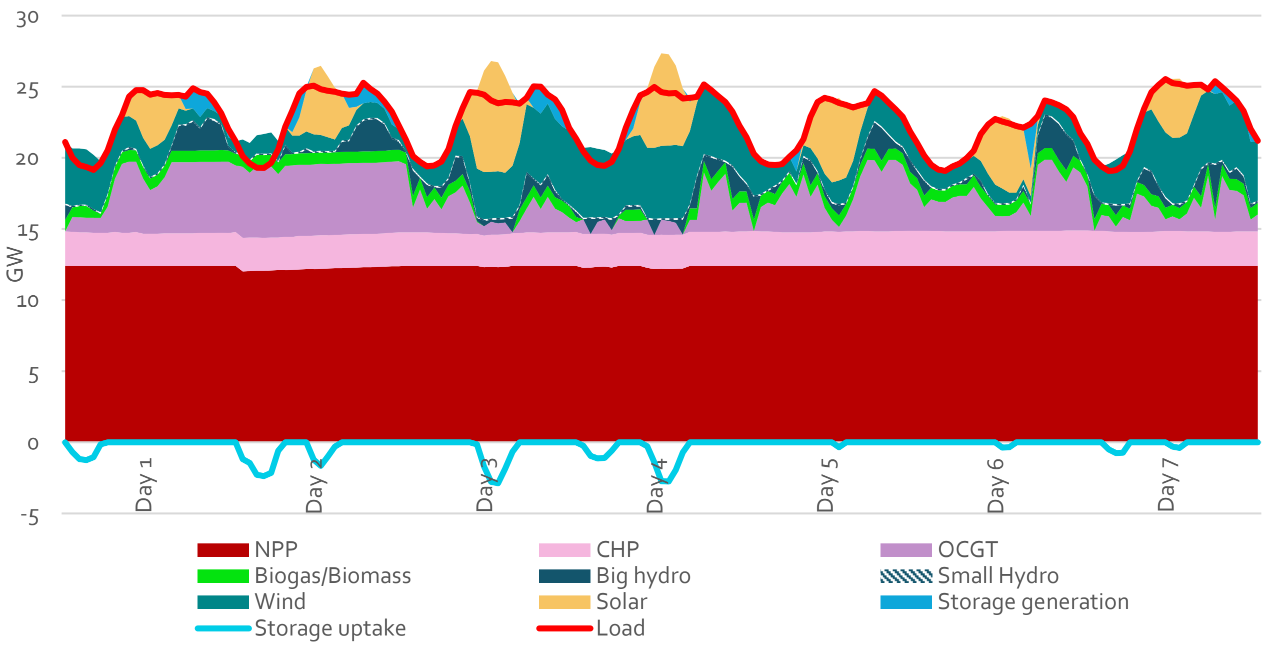
Source: LCU

However, ODM reveals a possible drawback of this scenario: NPPs are utilised more than in the *reduced coal* scenario, providing 104.5 TWh compared to 101.5 TWh. But Figure 8 reveals that OCGT run at high loads of around 5 GW (out of 7.8 GW of total installed capacity) for protracted periods of time. This requires a substantial volume of gas – 2.3 bn m³ – which both creates costs and presents problem due to import needs.

It appears that either a load-following ("shoulder") technology, which does not require to run absolutely flat (NPPs) but also does not need to be highly flexible would be useful, or the capacity of RES needs to be increased to reduce continuous operational needs for OCGTs. We hence developed the two final scenarios, based on a TPP/OCGT mix (*combined*) and an OCGT/RES mix (*renewable+*).

[26] Agora Energiewende (2017) 'Flexibility in thermal power plants. With a focus on existing coal-fired power plants', Study, 115/04-S-2017/EN

Figure 8: Power generation by source for one week in winter, *gas turbines* scenario

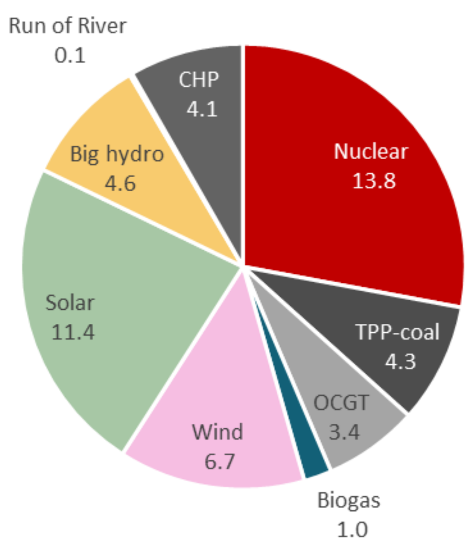


Source: LCU

4.6 Scenario 4: Combined

This scenario takes the latter option to prevent OCGTs from having to run in a baseload function. By installing a mix of (retrofitted) TPPs and OCGTs, the idea of this scenario is to allow TPPs to work in a baseload function to cover the difference between usual power supply by NPPs plus RES and power demand whilst reserving OCGTs for the role of providing flexibility to accompany the volatile RES output. Out of 49.5 GW of total installed capacity, TPPs make up 4.3 GW (8.7%) and OCGTs make up 3.4 GW (6.9%). This corresponds to retrofitting 5 TPPs (counted as LCPs), 5 less than in the *reduced coal* scenario.

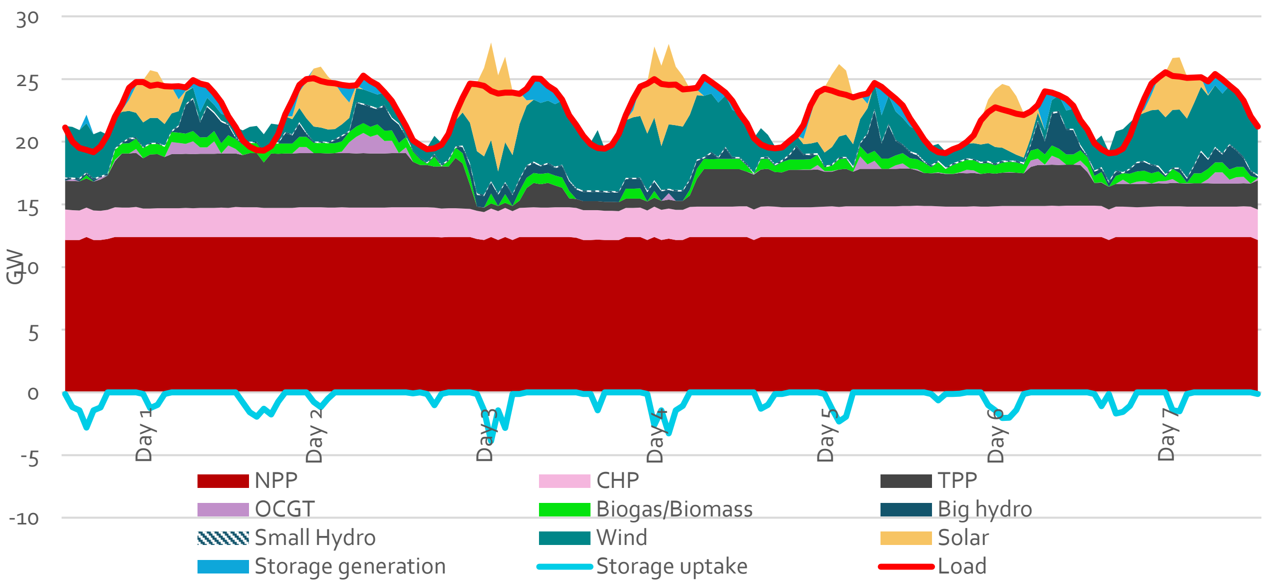
Figure 9: Installed capacity in the *combined* scenario, GW



Source: LCU

Modelling shows that indeed this capacity configuration appears to allow each type of plant to serve in its optimal role. TPPs provide the "shoulder" capacity and OCGTs only become active to balance volatility in RES output with demand when hydro and biogas capacities are insufficient. In total, OCGTs only need to provide 0.5 TWh of power compared to 9.8 TWh in the *gas turbines* scenario but provide sufficient up-reserves which leads to a crowding-out of TPP generation (see Table 5). This reduces needs for gas fuel to a more manageable 133 m m^3 per year. However, NPPs are utilised less than in the other scenarios with only 100.7 TWh compared to 104.5 TWh (gas turbines) or 101.5 (reduced coal).

Figure 10: Power generation by source for one week in winter, *combined* scenario

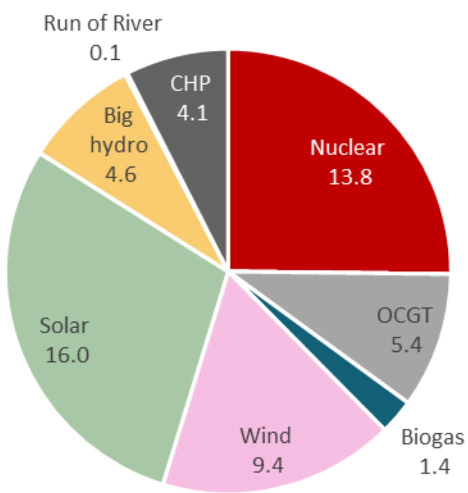


Source: LCU

4.7 Scenario 5: Renewable+

Finally, we investigate the option of adding even more RES capacity to reduce needs for continuous generation by OCGTs or TPPs (all previous scenarios already include existing plans to increase RES capacities). By increasing the installed capacity of RES (solar and wind only – hydro and biogas capacities are assumed to be unchanged as there are limitations to increasing their usage), an OCGT capacity of 5.4 GW without any need for TPPs can provide sufficient flexibility to ensure feasibility of the system. However, to ensure sufficient generation capacity from volatile renewable sources, RES capacities must be increased quite strongly. Whereas in previous scenarios, in accordance with Ukraine's Energy strategy, installed RES capacities of 6.7 GW of wind power and 11.4 GW of solar power were assumed, in this scenario, 9.4 GW of wind power and 16.0 GW of solar power capacities are assumed, an increase of 2.7 GW of wind and 4.6 GW of solar power capacity respectively.

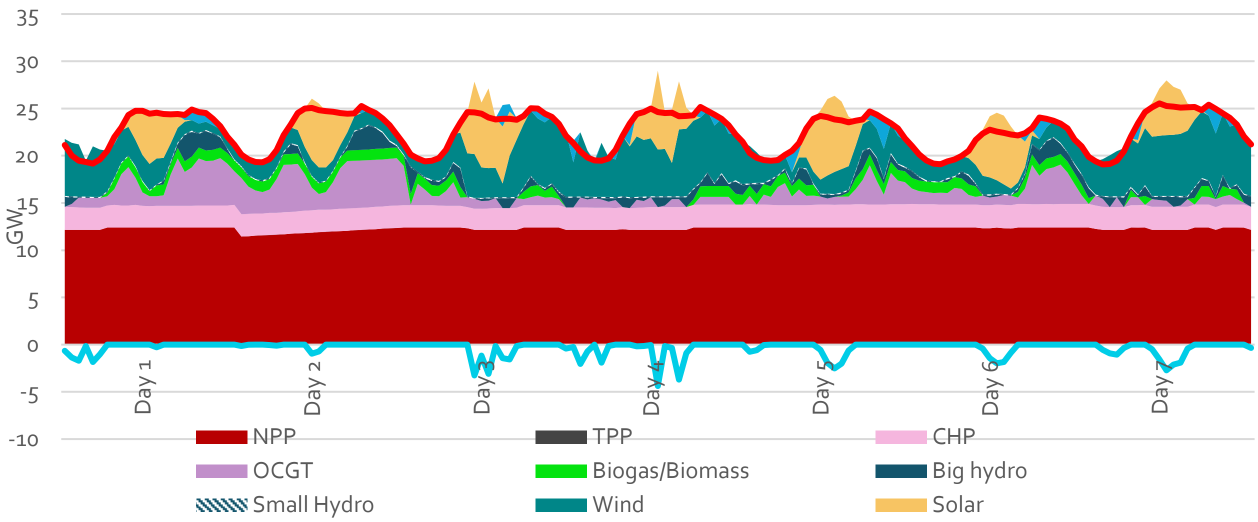
Figure 11: Installed capacity in the *renewable+* scenario, GW



Source: LCU

ODM results show that this system is not fully optimal. OCGTs are required for relatively long periods of time as the additional RES are not available at all times. It appears likely that higher capital costs of additional RES capacity may not be outweighed by savings in capital costs and fuel costs for OCGTs. Although only 5.4 GW of OCGT are needed here, compared to 7.8 GW in the *gas turbines* scenario, OCGTs provide a rather substantial total of 6.2 TWh (*gas turbines* scenario: 9.8 TWh).

Figure 12: Power generation by source for one week in winter, *renewable+* scenario



Source: LCU

5 Scenario results

Although the optimal dispatch results already gave indications of potential weaknesses of each scenario, a comparison requires analysing the totality of costs of power generation in each scenario, including capital and operational costs. As described in chapter 3, we have annualised the CAPEX resulting from investments (new plants, retrofits, lifetime enhancements) in a way that allows a proper comparability of the different forms of power generation from the perspective of the real costs of the plants, all of which have ultimately to be borne by the Ukrainian economy.

5.1 Annual total costs

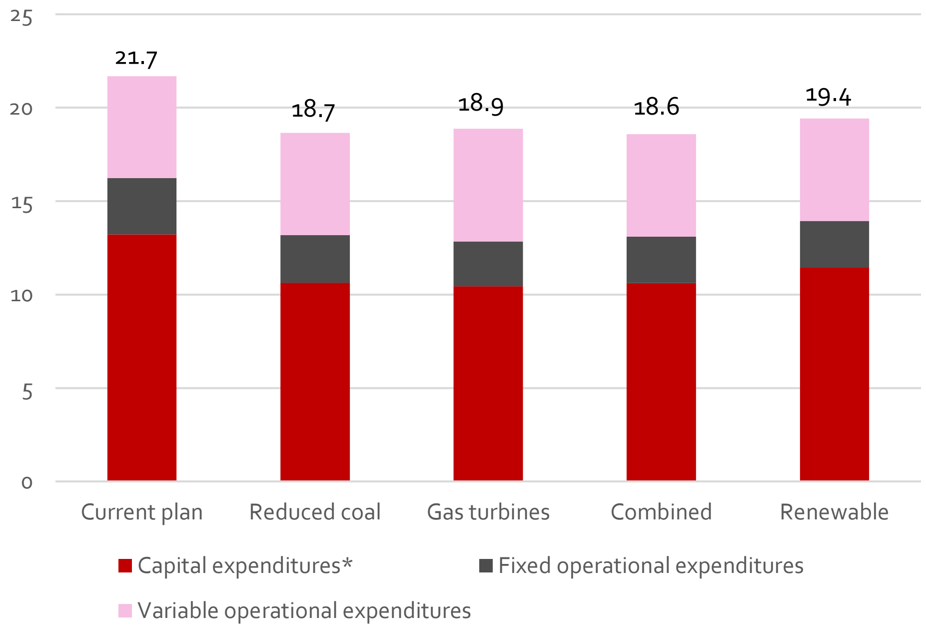
Summing up total costs in each scenario yields the clear-cut conclusion that the *current plan* scenario is by far the most expensive. With annual total costs of EUR 21.7 bn, it is around EUR 3 bn more expensive per year than essentially all other scenarios as it contains a multitude of TPPs that are not needed for power generation or as a reserve. All other scenarios are relatively close in their total costs ranging between EUR 18.6 bn and EUR 19.4 bn.

According to our calculation, the *combined* scenario is indeed the cheapest scenario at EUR 18.6 bn per year, but the *reduced coal* scenario appears to be almost as inexpensive. The *gas turbines* scenario appears to be just slightly more expensive.

The mechanics behind the cost differences can be understood by looking at the breakdown of costs in Table 6. Indeed, the retrofits, modernisation and replacement of an excessive amount of TPPs are behind the excessive costs of the *current plan* scenario as they drive the CAPEX up by around EUR 2.5 bn compared to the other scenarios. Higher CAPEX also explains the cost disadvantage of the *renewable+* scenario, indicating that higher investment costs due to the need for more renewable capacity is not made up by significant savings in any OPEX component.

Crucially, among the three scenarios with lowest costs, the costs of the *reduced coal* and *combined* scenarios are extremely similar at aggregated level. Higher investment costs for new plants (OCGTs) in the *combined* scenario are offset by savings on lifetime extensions and retrofits for TPPs. Fuel costs are essentially equal. In the *combined* scenario, higher fuel costs of OCGTs are balanced by less need for TPP generation and less overall generation due to more efficiency in the system. The slightly higher costs of the *gas turbines* scenario are mainly driven by higher fuel costs due to OCGTs having to provide some shoulder capacity: While OCGTs produce 9.8 TWh in the *gas turbines* scenario, they only produce 0.5 TWh in the *combined* scenario, with 12 TWh of shoulder generation taken over by TPPs.

Figure 13: Total annual costs of the scenarios, EUR bn



Source: LCU

Regarding the key issue of how many TPPs should be in the generation mix by 2033, it is important to highlight the importance of assumptions regarding possible TPP lifetimes: Along the lines of the existing NERP, we assume in our calculations that sufficiently many TPPs (sufficient to cover generation needs in all scenarios) can be retrofitted with filters and given a lifetime extension investment in order to serve beyond 2033. If these plants, many of which are indeed extremely old, cannot however be modernised and need to be replaced by entirely new ones, CAPEX in the TPP-intensive scenarios would increase substantially: Assuming, in the extreme, that all TPPs would need to be replaced before 2033 would change the order of the cheapest scenarios: The *reduced coal* scenario would exhibit annual costs of EUR 19.4 bn and the annual costs of the *combined* scenario would increase to EUR 18.9 bn. Hence, the *gas turbines* and *combined* scenarios would be in a tie for the cheapest scenario, whereas the TPP-intensive *reduced coal* scenario would be clearly uneconomical – for the same price tag, one could instead build a much cleaner system with a yet higher share of RES (the *renewable+* scenario).

Also, due to the close proximity of the cost results for the three top scenarios – *reduced coal*, *gas turbines* and *combined* – the precise cost order of these scenarios is sensitive to cost assumptions. Hence, the decision on which scenario to implement should not only revolve around minimizing costs but also include considerations of which technology mix would be most compatible with future developments in the energy sector, and of course, CO2 emissions.

Table 6: Total annual cost breakdown of scenarios, EUR bn in 2021 prices

	Current plan	Reduced coal	Gas turbines	Combined	Renewable+
CAPEX	**13.2**	**10.6**	**10.4**	**10.6**	**11.4**
New plants	5.5	4.2	4.9	4.5	5.9
Lifetime extensions	7.0	6.1	5.5	5.9	5.5

Retrofits	0.7	0.3	0.0	0.2	0.0
Fixed OPEX	**3.0**	**2.6**	**2.4**	**2.5**	**2.5**
Fixed O&M for retrofits	0.1	0.0	0.0	0.0	0.0
Fixed O&M for plants	2.9	2.5	2.4	2.5	2.5
Variable OPEX	**5.5**	**5.5**	**6.0**	**5.5**	**5.5**
Variable O&M	1.1	1.1	1.1	1.1	1.0
Fuel Costs	4.4	4.4	5.0	4.4	4.5
Total annual costs	**21.7**	**18.7**	**18.9**	**18.6**	**19.4**

Source: LCU

5.2 Investment needs

The total required investment volume relates to investments that need to be made between now and 2033. It effectively mirrors the annualised CAPEX in the previous section if we make the simplifying assumption that each modernised power plant will only require one lifetime enhancement (with an assumed depreciation period of 10 years) over this period.

Of interest are mainly the lifetime extension and retrofitting costs for TPPs as well as the costs for replacement TPPs and new OCGTs and RES plants. Other required investments (lifetime extensions of other existing plants, replacements of CHPs, construction of pump storage plants) do not change between the scenarios. Hence, the total investment need is not the main variable of interest here, rather the specific investment needs in fossil fuel technologies and RES.

Table 7: Expected investment needs until 2033, EUR bn

		Current plan	Reduced coal	Gas turbines	Combined	Renewable+
Retrofits	TPP	3.5	1.3	-	0.8	-
	CHP	0.2	0.2	0.2	0.2	0.2
	Total	**3.6**	**1.5**	**0.2**	**0.9**	**0.2**
Lifetime extensions	TPP	7.5	3.2	-	2.1	-
	OCGT	-	-	-	-	-
	Others	27.5	27.5	27.5	27.5	27.5
	Total	**35.1**	**30.7**	**27.5**	**29.6**	**27.5**
New plants	TPP	8.4	-	-	-	-
	OCGT	-	-	4.8	2.1	3.3
	RES	13.7	13.7	13.7	13.7	21.5
	Others	13.5	13.5	13.5	13.5	13.5
	Total	**35.6**	**27.2**	**31.9**	**29.3**	**38.3**
Total investment		**74.3**	**59.4**	**59.6**	**59.8**	**65.9**

Source: LCU

It is evident that the high investment requirements in the *current plan* scenario are due to the modernisation and replacement of many unnecessary TPPs, leading to excess investment costs of almost EUR 15 bn compared to the three cheaper scenarios. Even if we exclude the plan to replace the TPP with new coal-fired power plants (as foreseen in Annex IV), the *current plan* would be the most expensive scenario. Due to high retrofitting and lifetime extension costs for the TPP capacity, it would exceed the investment needs of the other scenarios by around EUR 5 bn.

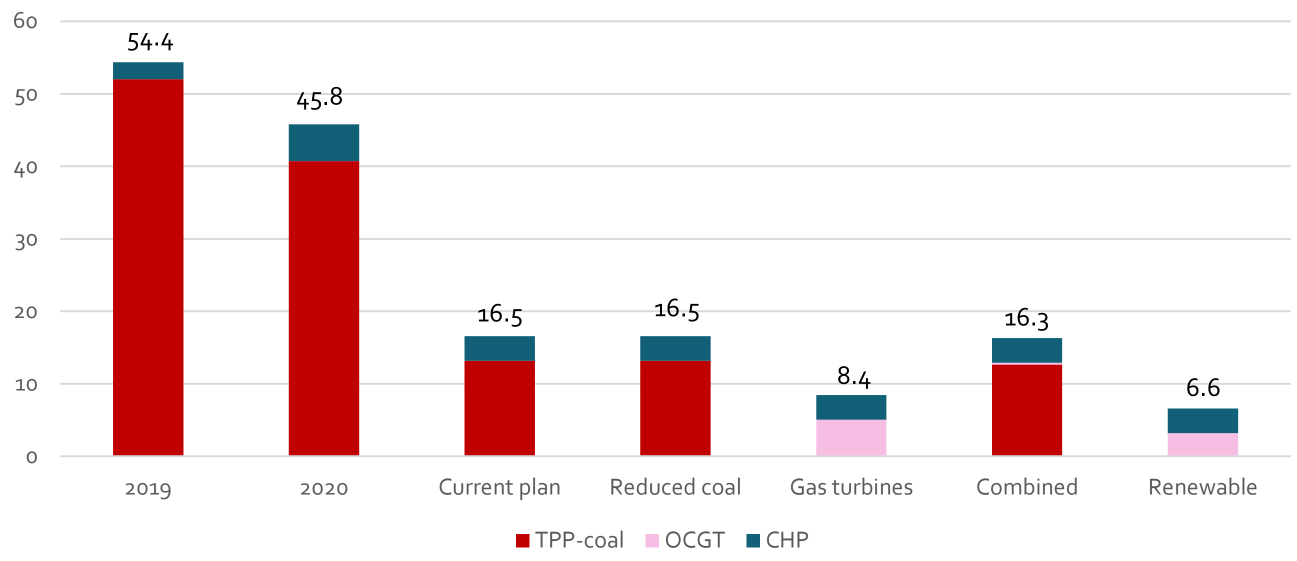
The *reduced coal* scenario exhibits higher investment needs for retrofits and lifetime enhancements of TPPs (EUR 4.5 bn), it requires no investment into new TPPs or OCGTs. The *gas turbines* scenario requires no lifetime extensions and retrofits of TPPs (as all of them are to be retired by scenario design) but requires EUR 4.8 bn of investment into new OCGTs. With EUR 2.9 bn for lifetime extensions/retrofits of TPPs and EUR 2.1 bn for new OCGTs, the *combined* scenario aptly presents a middle ground between the previous two scenarios, with slightly higher total investment needs (which are, as previously discussed, outweighed by lower OPEX in the perspective of annual total costs).

The *renewable+* scenario requires no modernisation of TPPs but EUR 3.3 bn investment in new OCGTs as well as EUR 7.8 bn in additional RES capacity compared to the other scenarios. This basically is the reason for its elevated total annual costs that rendered it more expensive than the previous three scenarios. Importantly, except for the *current plan* scenario, none of the scenarios require investments into new TPPs. The existing NERP identifies a sufficient number of TPPs as fit for retrofitting and the combination of investments into retrofits and lifetime extension is always cheaper in annual CAPEX than construction of a new plant and also has the advantage of not further locking Ukraine into coal power through new plants with long depreciation periods.

5.3 Relation to decarbonisation agenda

As is to be expected, CO_2 emissions will decline substantially if any of the capacity combinations modelled are to be built and dispatched optimally. TPPs will reduce their power production from almost 40 TWh in 2020 to 12.8 TWh in the *current plan* and *reduced coal* scenarios. In the other scenarios, TPP generation is replaced by more generation of (cleaner) OCGTs. OCGTs emit only 0.5 tCO_2/MWh_{el} compared to 1 tCO_2/MWh_{el} for coal-fired TPPs[27].

Figure 14: Total CO_2 emissions of electricity generation, $MtCO_2$



Source: LCU

Note: Electricity-related emissions only, CHP emissions attributed proportionally to power and heat output.

In effect, CO_2 emissions of the electricity sector will decline substantially in each of our scenarios compared to present levels purely in virtue of less dispatch of TPPs. Even in the coal-intensive scenarios (*current plan*, *reduced coal* and *combined*), total CO_2 emissions of 16.5 Mt are just above one third of levels in 2020, which were already depressed due to lower economic activity during the Covid-19 pandemic.

The two scenarios that assume decommissioning all TPPs (*gas turbines* and *renewable+*) offer yet further reductions of CO_2 emissions to 8.4 $MtCO_2$ and 6.6 $MtCO_2$, respectively. As in the other scenarios, 3.4 $MtCO_2$ out of this total are generated by CHPs whose capacity and generation we assumed as fixed. Hence, the *gas turbines* and *renewable+* scenarios offer further substantial reductions of CO_2 emissions at a relatively modest price tag, especially the *gas turbines* scenario. This aspect should be intensively considered when revising the NERP and contemplating the future park of power plants.

All of our scenarios result in significantly lower CO_2 emissions than the NDC2 draft, in which 28 $MtCO_2$ of emissions from the electricity sector are aimed at for 2030. A crucial difference between the approaches is the

[27] The efficiency in converting thermal input to power output is substantially higher for OCGTs than for TPPs.

assumption of total power demand, which is assumed to be at 190TWh in 2030 by NDC2 and at 172 TWh in 2033 in our paper, based on Ukrenergo's "Adequacy report 2020". Taking this into account, the power system of the NDC2 draft Policy Scenario emits 260 gCO2/kWh while in our scenarios emissions range from 100 gCO2/kWh to 40 gCO2/kWh. The lower power demand in combination with a higher dispatch of NPPs in all our scenarios shows a high emission saving potential.

Table 8: Total annual cost of scenarios including carbon price of 40 EUR/tCO2, EUR bn

	Current plan	Reduced coal	Gas turbines	Combined	Renewable+
CAPEX	13.2	10.6	10.4	10.6	11.4
Fixed OPEX	3.0	2.6	2.4	2.5	2.5
Variable OPEX (excl. Carbon price)	5.5	5.5	6.0	5.5	5.5
Carbon price	**0.9**	**0.9**	**0.6**	**0.9**	**0.5**
Total annual costs	**22.6**	**19.6**	**19.4**	**19.5**	**19.9**

Source: LCU

To include the consideration of decarbonisation more systematically, we calculated the costs of the scenarios including a carbon price of 40 EUR/tCO2 as suggested by LCU (2021)[28]. In the social planner perspective taken here, this includes the cost of CO2 emissions as an "internalised externality". Hence, understanding the carbon price not as a tax but indeed as the genuine costs of emissions to society, the cheapest scenario under this calculation is indeed the one that should be preferred when including environmental/climate considerations. Total costs of CO2 emissions range are EUR 493 m for the *renewable+* scenario, EUR 568 m for the *gas turbines* scenario, EUR 885 m for the *combined* and EUR 893m for the *reduced coal* and *current plan* scenarios. Indeed, as Table 8 shows, under this internalisation, the *gas turbines* scenario is indeed the cheapest scenario overall, whilst the *renewable+* scenario remains more expensive than the *current plan* and *reduced coal* scenarios.

In sum, the choice of what configuration of Ukraine's power plant park is aimed at as the endpoint of the NERP has important relations to the decarbonisation agenda of the country. For a relatively small surcharge (modelled here as a CO2 price), the emissions intensity of the electricity sector can basically be halved compared to the TPP-centred scenarios (which already would be a major improvement over the present setup if dispatched optimally). Another advantage of moving to a more RES/OCGT focused scenario would be that the power plant park would already be better configured for future developments. New OCGTs compared to modernised TPPs would be a more forward-looking configuration in view of potential further increases of the RES share (perhaps to replace ageing NPPs in the long term).

5.4 Conclusions

The *combined* and *gas turbines* scenario are the most attractive "target scenarios" for a revised NERP. Whilst exhibiting similar costs to the *reduced coal* scenario in the basic cost calculation, they have some clear advantages of the *reduced coal* scenario: For almost the same costs, they lead to fewer emissions (especially the *gas turbines* scenario) and present steps into transitioning the power plant park towards the configuration required further in future. Also, the *reduced coal* scenario only is cost-attractive as long as sufficiently many existing TPPs can indeed be retrofitted and modernised to serve through 2033. Replacing TPPs with new units rather than modernising and retrofitting would be much more expensive than constructing new OCGTs and leave Ukraine with a technologically backward asset base, possibly stranded assets.

The *renewable+* scenario, foreseeing a yet larger deployment of RES is not yet attractive, probably due to a combination of the costs of storage and due to baseload provision by NPPs conflicting with the generation peaks of RES. However, all other scenarios already incorporate significant expansion of RES capacities compared to the present according to existing plans.

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[28] Breuing, Julia (2021) 'A revision of Ukraine's Carbon Tax', LCU Policy Note https://www.lowcarbonukraine.com/en/a-revision-of-ukraines-carbon-tax/

Choosing between the *combined* and the *gas turbines* scenario (or designing a variation thereof) will essentially depend on the trade-off between the preference for a cleaner and more flexible generation mix (favouring OCGTs in the *gas turbines* scenario) and reducing the need for *gas turbines* (favouring the *combined* scenario with little need for gas supplies). This will have to be a political choice.

6 Implications for a possible revision of the NERP

6.1 Main implications

Immediate political action by Ukraine is required.

With its membership of the EnC, Ukraine has committed itself firmly to implement the *acquis Communautaire* including the LCPD and IED legislation. To make good on these commitments, the Ukrainain Ministry of Energy developed a NERP that was accepted by the EnC in 2017 and amended in 2019. It is a binding commitment of Ukraine to reduce the relevant emissions of its LCPs according to the aggregated ceilings and opt-out regulations. Implementation of the NERP has however not begun in any substantial way. No regulations or measures to ensure modernisation, decommissioning or replacements of non-compliant TPPs have been implemented. Compliance with the obligations to date was essentially by accident – had the Covid-19 pandemic not occurred, Ukraine would have (in all probability) already been in breach of its commitments in 2020. For the coming years, it is at least very possible that Ukraine will exceed the aggregated ceiling of emissions for the TPPs under NERP and will be officially off-track.

It is hence **necessary and should be a top priority for Ukraine's energy policy to bring the process of LCPD/IED implementation back on track** and avoid opening of an infringement procedure against Ukraine by the EnC. **Ukraine needs to act now, offer an attractive proposal on how to modify existing commitments to the EnC and must implement these changed commitments for immediate implementation on the ground**. A simple deferment of deadlines and further relaxation of compliance conditions as suggested by the Ministry of Energy's advisory group appears unlikely to find the necessary approval of the Ministerial Council of the EnC (which includes EU member states and requires a proposal by the European Commission). Hence, **Ukraine must offer a package that includes more environmental ambition than the present plan in order to start a revision process and avoid open confrontation on breach of obligations in 2021**.

Reducing the role of TPPs post-2033 makes economic and ecologic sense.

Although one might expect that offering an environmentally more ambitious deal to the EnC to restart negotiations on the NERP would be costly for Ukraine, the opposite is the case. Economic considerations actually support offering a more environmentally ambitious deal to the EnC. The current plans including the NERP are grossly deficient with regard to considering the future needs for TPPs. Planning for retrofitting or replacement of the entire park of existing TPPs, the plans ignore other ongoing plans and developments, especially the expansion of the share of RES in the generation mix, and the optimal dispatch of power plants (especially NPPs).

The present NERP would require investments that are as high as they are unnecessary. It foresees the retrofitting of 21 TPPs (counted as LCPs) and even the construction of 16 new TPPs to replace decommissioned plants. It would leave Ukraine with stranded assets of new or modernised TPPs that are unused and unsuitable for the energy system of the future along with their costs.

Any modification of the NERP should hence incorporate a sharp reduction or indeed phase-out of the role of coal-fired TPPs. Our scenarios demonstrated that a maximum of 13 TPPs (counted as LCPs) (in the *reduced coal* scenario) is required by 2033. In the other scenarios, less or even no TPPs at all are required in 2033 for similar total costs. The *combined* (with 5 TPPs retrofitted) and the *gas turbines* scenario (with full decommissioning of all TPPs) are most attractive economically. Which of them (or variation thereof) should be the endpoint of a revised NERP needs to be carefully decided in a political process that includes stakeholder consultation and incorporation of independent analysis. It is clear that the role of TPPs will be significantly smaller than in the present NERP.

6.2 Next steps

Revising the NERP will be a complex procedure involving many levels: A revised NERP should make economic sense for Ukraine at large, needs to be acceptable at international level for the EnC and implementable at national level among the stakeholders of Ukraine's energy system. We identify seven concrete steps that need to be taken:

1) **Ensuring political alignment in UKR**: As a precondition, the discussion on the NERP can only be sensibly re-opened if there is a commitment to reduce the role of TPPs compared to the existing NERP among the vital Ukrainian decisionmakers. Without this commitment, the further process would certainly not result in a successful revision, damaging Ukraine's interests in multiple ways (being visibly off-track with regard to a key international obligation and ambition and possibly subject to an infringement procedure; requirement to implement an economically and ecologically bad existing NERP).
2) **Setting up the process of NERP revision:** Due to the complexity of the matter, care should be taken in designing the specific and institutional aspects of the further required process. This especially concerns the questions on when (at what stages) and how consultation and coordination with stakeholders in Ukraine's energy sector and with the EnC should occur and how analytical support can be best included in the process. The next steps are to be understood as a sketch of the components of this process.
3) **Deciding on the endpoint of the NERP:** Taking into account the results of this study and further analyses and inputs to be elaborated (e.g. refining cost assumptions and adding information on possible lifetimes of existing TPPs), an informed decision must be taken on what power generation system the NERP should actually be the transition device for. Most importantly, what shall be the role of TPPs at the end of the NERP in 2033? How many will still be required, considering the total capital and operational costs. This will be a key decision without which the transition process cannot be optimally designed and it depends on political coordination with other plans concerning RES expansion and the future of other power sources in Ukraine, especially nuclear energy.
4) **Formulation of the NERP:** After a decision on the endpoint of the NERP, a rule-compliant NERP (including the opt-out lists) needs to be drawn up that selects what (if any) of the TPPs are to be retrofitted and modernised and how the gradual decommissioning of the rest of the power plants is to occur. This requires intensive consultation with Ukrenergo and the power plant operators in order to design an efficient plan that minimises costs. Also, it of course involves crucial negotiations or at least co-ordinations with the EnC in order to ensure that Ukraine's offer will be acceptable during political negotiations and by the Ministerial Council of the EnC.
5) **Designing an implementation strategy**: Already before a revised NERP is accepted by the EnC, an implementation strategy needs to be drawn up. It must set out practical and implementable instruments that will lead to the reality corresponding to the plan, considering that most power plants in Ukraine are privately owned and operated. Instruments should force and/or incentivise operators to retrofit or decommission plants as required by NERP commitments and to build new assets in time. Classes of instruments will be regulatory measures (revoking licenses to operate or stopping to purchase energy from plants that are to be decommissioned or were not modernised in time) as well as market/financial instruments.
6) **Formal revision of the NERP:** The new and revised NERP needs to be accepted by the EnC.
7) **Implementation**

This process will not be easy. Interests of multiple stakeholders must be aligned and several dimensions of technical constraints need to be observed. Nevertheless, Ukraine must embark on this process as soon as possible. Currently, the country has fallen behind on its obligations. It is, both, up to Ukraine to get back on track and in its best interests to do so to avoid international fallout as well as having to rush and catch up with implementing an economically and ecologically wasteful current NERP.

Annex

A1: Sensitivity of results to assumptions

Our results are sensitive to assumptions. We have attempted to make these assumptions as reasonable and based on contemporary evidence and research as possible. Also, our calculations are open to replication and modification by interested stakeholders. Nevertheless, there are some assumptions that merit discussion here:

- **Modernisation costs of existing powerplants**: Our assumption of the necessity of a lifetime extension investment of 25% of the cost of a new plant every 10 years may seem at odds with Ukrainian reality in which many existing power plants, especially TPPs, are old and have seen very little investment over the past years. However, we believe that considering a continuation of this approach for as long a time period as until 2033 and beyond to be unrealistic. Without substantial investment, existing old power plants are unlikely to last. Also, industry sources indicated that retrofits of filters will necessitate at least some further modernisation and constructive reinforcement of TPPs. Nevertheless, if operation of existing TPPs beyond 2033 is feasible with lower investment costs for lifetime extensions than assumed here, this would tilt our results in the opposite direction, favouring the *reduced coal* and *combined* scenarios with heavy reliance on TPPs as a power source post-2033.[29]
- **Capital costs:** Although a present fact rather than an assumption, the high costs of capital in Ukraine (we assume an interest rate of 15%, corresponding to current costs of credit for large Ukrainian companies) accentuate the importance of CAPEX vs OPEX in total costs. This favours scenarios with less investment needs and hence those with more retrofits of existing TPPs rather than construction of new OCGTs and RES capacities.
- **Energy demand**: Our assumption of energy demand, as mentioned previously, is based on Ukrenergo's 2020 adequacy report. If demand in 2033 should turn out higher (e.g. as assumed by the NDC2 scenarios), additional generation capacity would be required. What exact types of capacity/technology would be optimal, would however depend on the intra-year demand profile.
- **Constant role of other power generation capacities**: To keep our set of assumptions simple, we assumed an unchanged role and capacity of all power sources except TPPs, OCGTs and RES. Especially changes to the intended role of nuclear power would however have wide-ranging implications and require a new approach to the baseload of the system (but no such plans exist to date). Whether it could better be substituted by retaining, retrofitting or replacing more TPPs or a combination of OCGTs and RES would need to be investigated separately. Also, changing the installed capacities of biomass/biogas plants and hydroelectric plants could affect our results somewhat as these are flexible sources of power (especially hydro). However, no plans for further hydroelectric plants exist and it is not realistic to quickly develop such projects. Increasing the role of biomass as a source of power, on the other hand, is possible but would raise many other questions, which requires a separate treatment.

[29] Modifications on the costs of lifetime extensions would also affect the costs of the rest of the existing power plant stock (nuclear, hydro etc) but without affecting the cost differentiation among the scenarios.

A2: Emission Limit Values in the LCPD and IED

Table 9: Emission limit values for solid fuels (excl. biomass) under LCPD

	Total rated thermal input in MW	NOx, mg/ Nm³	SO2, mg/ Nm³	Dust, mg/ Nm³
Existing plants (permit granted before 2012)	50-500	600*	2000-400 (linear decrease)	50
	>500	500* 200* (since 2016)	400	100
New plants (permit granted since 2012)	50-100	400	850	50
	100-300	200	200	30
	>300	200	200	30

Source: Directive 2001/80/EC of 23 October 2001 on the limitation of emissions of certain pollutants into the air from large combustion plants (Annex III-VII); The Energy Community Legal Framework, 4th edition (January 2018), Article 4
** The ELVs for NOx may differ depending on the hours of operation.*
Note: NOx requires secondary abatement of hard coal; Nm3 is a unit of volume measurement used to compare gas quantities present at different pressures and temperatures (operating condition, operating volume).

Table 10: Emission limit values for solid fuels (excl. biomass) under IED

	Total rated thermal input in MW	NOx, mg/ Nm³	SO2, mg/ Nm³	Dust, mg/ Nm³
Existing plants (permit granted before 2018)	50-100	300/450*	400	30
	100-300	200	250	25
	>300	200	200	20
New plants (permit granted since 2018)	50-100	300/400*	400	20
	100-300	200	200	20
	>300	150/200*	150/200**	10

Source: Directive 2010/75/EU of 24 November 2010 on industrial emissions (integrated pollution prevention and control) (Chapter III, Annex V, Part 1 & 2)
** in case of pulverised lignite combustion*
*** in case of circulating or pressurised fluidised bed combustion*
Note: NOx requires secondary abatement of hard coal; Nm3 (normalised cubic meter) is a unit of volume measurement used to compare gas quantities present at different pressures and temperatures (operating condition, operating volume.

Table 11: Aggregated emission ceilings for all 90 existing large combustion plants included in the Ukrainian NERP (ton per year)

Date	SO_2	NOx	Dust
31 Dec 2018	1,017,035	191,300	205,878
31 Dec 2019	920,432	182,133	185,808
31 Dec 2020	823,969	172,966	165,737
31 Dec 2021	727,226	163,799	145,666
31 Dec 2022	630,623	154,631	125,596
31 Dec 2023	534,020	145,464	105,525
31 Dec 2024	437,417	136,297	85,455
31 Dec 2025	340,814	127,130	65,384
31 Dec 2026	244,210	117,962	45,313
31 Dec 2027	147,607	108,795	25,243
31 Dec 2028	51,004	99,628	5,172
31 Dec 2029	51,004	90,460	5,172
31 Dec 2030	51,004	81,293	5,172
31 Dec 2031	51,004	72,126	5,172
31 Dec 2032	51,004	62,959	5,172
31 Dec 2033	51,004	53,791	5,172

Source: National Emission Reduction Plan for Ukraine

Table 12: The distribution of LCPs among the Annexes of the NERP (as given in NERP)

Annexes	Description		Number of LCPs			Thermal power in GW		
			TPP	CHP	Total	TPP	CHP	Total
Annex II	All LCPs in NERP		27	63	90	42.4	22.5	64.8
incl. Annex III	*Specific retrofitting measures for LCPs in NERP*		*27*	*5*	*32*	*42.2*	*3.2*	*45.4*
Annex IV	Opt-out	20,000 hours until 2024	4	13	17	3.7	3.4	7.1
		40,000 hours until 2034	15	39	54	24.5	9.3	33.8
LCPs neither in Annex II nor in Annex IV			-9	71	62	0	10.2	10.2
Annex I	All plants falling under the LCPD		37	186	223	70.5	45.4	115.9

Source: NERP

Note: The inconsistency in counting the LCPs in the NERP can be seen in row 'LCPs neither in Annex II nor in Annex IV', where TPPs sum up to -9. We therefore applied our own counting method, which is consistent with the listing of all LCPs in Annex I.