A feasibility study of using MV and LV distributed energy resources flexibility in a TSO/DSO coordination perspective: the case study of Milan, Italy

A. Bosisio*, A. Berizzi**, C. Mosca***, C. Vergine***, D. Castiglioni***, A. Morotti****
*Department of Electrical, Computer and Biomedical Engineering - University of Pavia, Via Adolfo Ferrata, 5 27100 Pavia, (*Italy*)
**Energy Department - Politecnico di Milano, Via La Masa, 34 20156 Milano (*Italy*)
***Dispatching and Control Department – Terna Rete Italia S.p.A., Via G. Galilei, 18 20016 Pero (*Italy*)
****Energy Planning Department, Unareti S.p.A., Via Ponte Nuovo, 100 20128 Milano (*Italy*)

***Abstract*—The massive penetration of Renewable Energy Sources, preminently wind and photovoltaic power plants, and Distributed Energy Resources (DERs), such as Combined Heat and Power plants, Battery Energy Storage System, Electric Vehicles impose additional challenges in power system planning and operation. Pushing towards a low-carbon electricity system can increase potential issues such as congestion management, voltage control, controllability, observability, and generation-load forecasting. In this context, coordinated actions between Transmission System Operators (TSOs) and Distribution Systems Operators (DSOs) could be a valuable solution. For instance, through the DERs installed on the distribution network, the DSO could help the TSO to relieve a network contingency on the HV/HHV grid. This paper proposes a feasibility study of TSO-DSO coordination that allows using DERs to solve transmission network criticalities, both in operational and short- to medium-term time horizons, that does not involve the exchange of sensitive information between the two utilities. A straightforward algorithm is proposed for evaluating DERs available flexibility in terms of active and reactive power, and for estimating the aggregated capability curve at the point of common coupling, i.e., the flexibility available downstream a HV/MV substation. The proposed algorithm has been applied to Milan's case study using real data from Unareti, the local DSO, and Terna, the Italian TSO.**

***Index Terms*--Distributed power generation, power distribution, power system management, power transmission.**

I. INTRODUCTION

The growing and rapid diffusion of Distributed Energy Resources (DERs), such as Renewable Energy Sources (RESs) [1], Electric Vehicles (EVs) [2], Battery Energy Storage Systems (BESSs) [3][4], and Demand Response (DR) systems [5], often located in the Distribution System Operator (DSO) network, poses new challenges in power system balancing, congestion management, voltage control, controllability, observability and forecasting of DERs, but, at the same time, makes available new opportunities in the management and planning of the electricity system as a whole. In this context, interaction with the Transmission System Operator (TSO) is essential, including the possibility for the DSO to provide support, among others, in terms of flexibility, balancing, voltage control, and congestion [6].

To successfully manage the aforementioned challenges, it is crucial that the TSO and DSO are efficiently coordinated to allow for the greatest possible flexibility and interoperability [7]. Directive (EU) 2019/944 of the European Legislation and Council of 5 June 2019 [8] lays down in Article 32 of the incentives for the use of flexibility in distribution networks, providing for the need for coordination between TSO and DSO, in particular:

- DSOs shall exchange all necessary information and coordinate with TSOs to ensure optimal use of resources, the safe and efficient operation of the system, and facilitate market development;
- The DSO shall consult all relevant system users and TSOs on the network development plan.

At the same time, the push for a constant and continuous energy transition towards the "fit for 55" targets [9], and the experience gained with the recent, is becoming increasingly necessary to plan the network, which, given the ever-increasing presence of distributed resources, requires new models of coordinated TSO-DSO planning.

The analysis of the technical regulations focused on the coordination between TSOs and DSOs is crucial to look for references in the network codes that regulate the activities in which the two entities must interface. To this end, the Italian network code [10] has to be analyzed to understand the types of information currently exchanged between TSOs and DSOs, the purposes of the information exchanged, and data on cooperation in the implementation of network development plans. Currently, the DSOs annually report data to the TSO on the installed power downstream of their network broken down by source type. Still, they do not provide details of their network, such types of information are, in fact, defined as sensitive and, therefore, not reported.

The key issues related to the interaction of TSOs and DSOs proposed in the current literature cover the domains of markets [11], network operations and network planning

[12], and data handling [13]. On the one hand, the literature shows an increasing number of papers dealing with the market framework in the last years, followed by network operation-related documents. Operational planning covers the third position in terms of papers number. On the other hand, data handling and expansion planning have rarely been investigated, and only a few papers or studies have been published.

Establishing an appropriate market framework is a prerequisite for ensuring DERs maximize the value of their assets and activity in the power system [14][15][16][17]. While TSOs and DSOs have traditionally not been visible or active in energy retail markets, they will have a growing stake in their development as DERs increasingly engage in providing system services, e.g., frequency response, reactive power, balancing, etc., and competing on the wholesale energy market. Developing a market for system services will require well-functioning retail markets where DERs can easily switch suppliers, have access to clear information, and make informed choices. The market framework should also define the roles and responsibilities of TSOs and DSOs and the process between them regarding their use of resources.

Given the DERs priority in the future energy system, operational actions must be optimized to support the necessary market framework while maximizing cost-efficiency and supply security [18][19][20][21][22]. As an increasing share of generation connects to DSO grids, in particular, the majority of RES is connected at low and medium voltage levels, one of the most operational challenges for TSOs is maintaining overall system security. As decentralized, non-synchronous forms of power production displace conventional forms of generation, TSOs have been left with a shorter pool of units available to provide system services, e.g., thermal generation providing frequency response, voltage control, and inertia. The growing scarcity of system services will become more acute in the future and necessitates new operational arrangements between TSOs and DSOs to unlock the capabilities of DERs to plug the shortfall in these services.

As with operational interaction, network planning processes between TSOs and DSOs need to be optimized and developed to support a DERs-centric market model [23][18][19]. This will require integrated planning approaches that recognize the growing interdependence of the transmission and distribution networks. Taking account of the increasing potential of DERs to provide system services, this should be incorporated into the planning stage. In this sense, network planning should be based on achieving the broadest possible net benefit that considers regional and European system needs.

Finally, establishing the necessary market framework with the concomitant operational and planning arrangements will require a new approach to data handling [26][27][28]. More data will not only become available through the entry of new market participants, such as energy service companies (ESCOs) or independent aggregators but will be needed for the enhanced requirements around observability and putting in place the market framework that supports DERs engagement. The question of data handling should be considered from two different perspectives. From a network operator point of view, TSOs and DSOs should define their needs and anticipate their future needs in terms of information exchange for the system's secure operation for both network planning purposes and real-time operations. Meanwhile, developments in the distribution networks have led to new requirements for operational data which can be difficult or costly to obtain, e.g., real-time information on small-scale RES levels, and DERs observability is not a reality for all TSOs and DSOs [29].

Within this framework, this paper proposes a feasibility study of TSO-DSO coordination which allows using DERs to solve transmission network criticalities, both in operational and short- to medium-term time horizons, that does not involve the exchange of sensitive information between the two utilities. A straightforward algorithm is proposed for evaluating DERs available flexibility in terms of active and reactive power, and for estimating the aggregated capability curve at the Point of Common Coupling (PCC), i.e., the flexibility available downstream a HV/MV substation (Primary Substation (PS))). Each DERs is analyzed, and based on the CEI 0-16 [30] and CEI 0-21 [31] standards, the capability curve is drawn. The CEI 0-16 states the required standard to connect active and passive users to the HV and MV networks, while CEI 0-21 states the required standard to connect active and passive users to the LV networks. The DERs power profile is derived from either real measured data coming from Unareti [32], the DSO of Milan and Brescia metropolitan area in Italy, or from the literature, while the load profile of the PS selected as the case study, as well as the output of transmission network analysis in the Milan area, from Terna, the Italian TSO. The primary outcome of applying the proposed methodology is to estimate the available flexibility, in terms of timing and intensity, to figure out the current and mid-long-term, i.e., 2030, potential contribution of the DERs to solve transmission network criticalities.

The remaining paper is designed as follows: Section II presents the methodology for estimating the DERs available flexibility and the aggregate capability curve at the PS level: in the meantime the proposed approach is presented, the study case of a PS in Milan is used to explain the procedure steps more clearly. Section III shows the detailed results of the presented study case, using statistics and focusing on intraday and seasonal variation on DERs flexibility. Moreover, an assessment of the PS potential contribution to transmission network contingency relieve is presented. Finally, section IV summarizes the main findings and outlines potential future work.

II. Proposed Methodology to Compute DERs Available Flexibility and the Resulting Aggregated DERs Capability Curve

The strategy implemented to obtain the resulting DERs aggregate capability curve is illustrated in Fig.1. The input data needed are the following: (1) yearly PS hourly values of active and reactive power. The values are measured and can refer either to a specific year or a combination of several years; (2) yearly DERs Per Unit (P.U.) hourly active power production. The curves are computed on historical data and customized based on the type of DER. The P.U. approach allows the algorithm to be highly flexible in studying as-is and mid-long-term scenarios as well as any PS whose input data are known; (3) capability curve of the DERs based on the Italian CEI 0-16 and CEI 0-21 standards; (4) installed power of each type of DER downstream the considered PS.

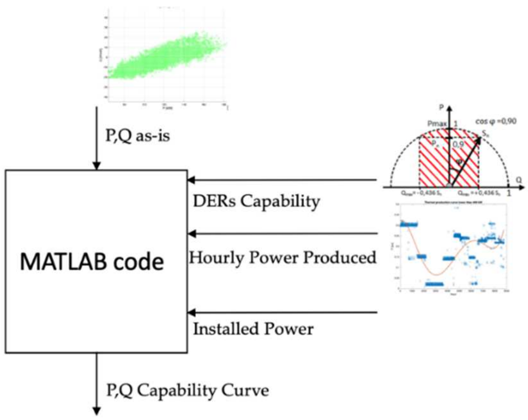


Fig. 1. Flow chart of the proposed methodology for DERs available flexibility and the resulting DERs aggregate capability curve.

It is worth to be mentioned that, for the sake of explaining, all the following data and results refer to the PS Sud, one of the PS located in Milan and operated by Unareti, whose primary data are reported in Table 1. The PS is connected to the national 220kV system and, using four transformers, step-down the voltage to 23 kV. The MV and LV systems connect 5 MW of PV, 420 kW of hydro, and 27 MW of CHP.

TABLE I

PS Sud main input data

PS main data			Installed capacity on MV/LV grid [MW]			
A_{nom} [MVA]	V [kV]	n° Tr	PV	Biomass/ Biogas	Hydro	CHP
376	220/23	4	5	-	0,420	27

It is worth noticing also that the proposed methodology used the capability curve given in the CEI 0-16 standard. In fact, for simplicity and based on the statistics reported in the Unareti Developing Plan [33], the authors assumed a predominance of DERs connected to the MV network, rather than the LV ones. As reported in table 5 of [33], in 2019, the electricity produced by MV DERs connected to the Milan distribution network was 213 GWh with respect to only 7 GWh generated by DERs connected to LV feeders.

A. PS yearly capability curve

As a first step, two vectors containing the 8760 hourly values of active and reactive power measured at the PS are loaded. Fig. 2 reports, for the sake of clarity, the yearly trend of active and reactive power measured at PS Sud, as well as in red the interpolating line.

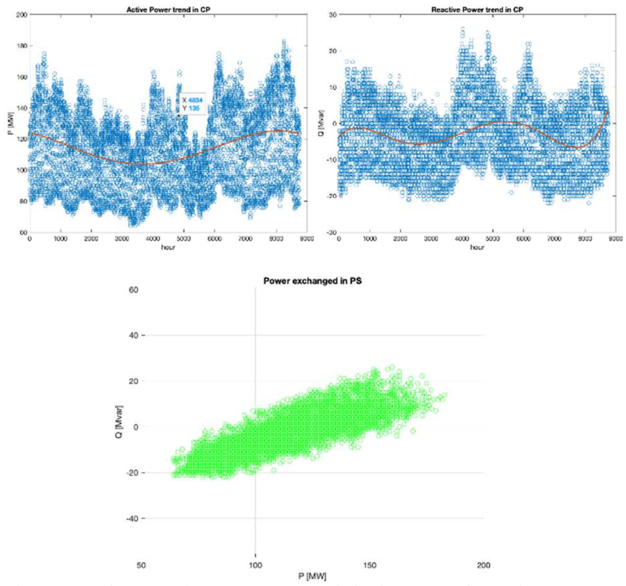


Fig. 2. Hourly PS active power (upper left picture) and reactive power (upper right picture) load profile. The lower plot is the PS yearly capability curve.

Moreover, the code plots on a 2D graph the 8760 values of active power on the X-axis and reactive power on the Y-axis to realize the as-is capability curve of the PS. It is worth noticing that this curve already contains the DERs contribution. The PS capability curve is reported in the lower part of Fig. 2. In the following, only the boundary points will be drawn to facilitate interpreting the simulation results.

B. DERs available flexibility computation

The second step of the procedure computes the available flexibility of each type of DER based on the yearly production trend and the capability curve laid down in CEI 0-16 standard.

PV power plants

The available PV flexibility is obtained from the yearly PV power output downloaded from PVGIS software [34]. By entering the PV installed power and the geographical location, PVGIS gives back the hourly annual power output, whose trend in P.U. is shown in Fig. 3. It is noticeable that, to take into account the yearly variability of PV production, the hourly average of the years from 2005 to 2020 has been considered.

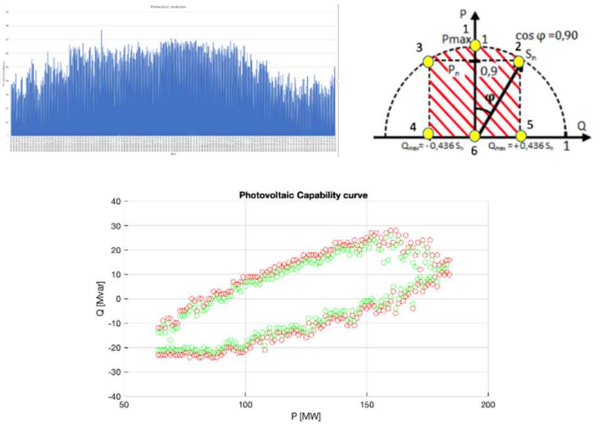


Fig. 3. Hourly PV power production in P.U. of the installed capacity (upper left picture); CEI 0-16 and standard capability curve considered for PV (upper right picture); boundaries of the as-is PS yearly capability curve in green, and considering the as-is PV flexibility in red (lower picture).

Once the yearly trend is obtained, the PV capability curve reported in Fig. 3 is applied to each hourly power production, assuming that the PV installed capacity equals the apparent power S_n. The area highlighted in red represents the PV control area, bounded by the six operating points specified in Fig. 3. Point 1 represents the PV production, which is dependent, hour by hour, on the available solar radiation. On the one hand, it is impossible to have extra active power (P_{upward}=0), while the $P_{downward}$ can be computed by considering the distance between points 1 and 6. On the other hand, exploiting the inverter's peculiarities makes it possible to feed (Q_{upward}) or absorb ($Q_{downward}$) reactive power into the grid, with a maximum power factor of 0.9, even if there is no active power production at that time.

Finally, starting from the PS active-reactive power measurements, the 8760 corresponding PV capability curves are drawn to find the flexibility from PV. Fig. 3 reports in green the boundary of the as-is PS yearly capability curve and the as-is PV flexibility in red.

CHP power plants

A similar approach has been implemented to estimate the available CHP flexibility. A statistical analysis has evaluated the hourly power production based on real data of several MV and LV CHP currently connected to the Unareti distribution network to find a standard yearly production trend. While real data are the blue dots in Fig. 4, the fifth-degree polynomial curve computed by interpolating the CHP P.U. hourly production is reported in red. Equation (1) is the fitting curve:

$$y = 1{,}89e^{-19}x^5 - 5{,}46e^{-15}x^4 + 5{,}43e^{-11}x^3 - 2{,}07e^{-7}x^2 + 1{,}67e^{-4}x + 0{,}67 \qquad (1)$$

where:

- y is the power production in P.U. of the nominal power;
- x is the considered hour.

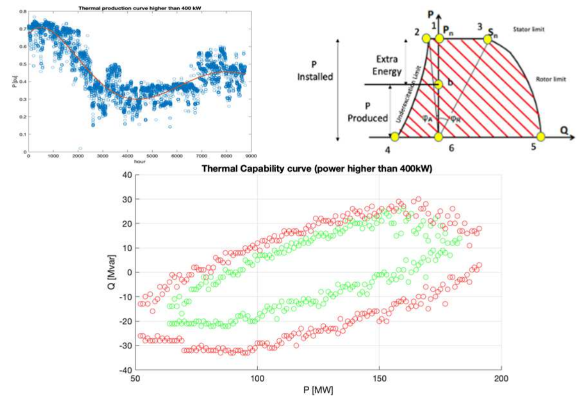


Fig. 4. Hourly CHP power production in P.U. of the installed capacity (upper left picture); CEI 0-16 and standard capability curve considered for CHP (upper right picture); boundaries of the as-is PS yearly capability curve in green, and considering the as-is CHP flexibility in red (lower picture).

Fig. 4 shows that CHP production is the highest during winter due to the increased thermal demand. On the other hand, production falls during the spring and summer, releasing potentially more considerable flexibility.

Once the yearly trend is estimated, the CHP capability curve reported in Fig. 4 is applied to each hourly power production, assuming that the CHP installed capacity equals the apparent power S_n. As for the PV, the red highlighted area represents the CHP control area, bounded by the six operating points specified in Fig. 4. Point b represents the CHP production. Contrary to PV, on the one hand, it is possible to exploit extra active power P_{upward}, i.e., the distance from point b to 1. $P_{downward}$ can be computed by considering the spread between points b and 6. It is worth noticing that P_{upward} and $P_{downward}$ vary between 30% and 70% of the install capacity. On the other hand, exploiting the synchronous generators' peculiarities makes it possible to feed (Q_{upward}) or absorb ($Q_{downward}$) reactive power into the grid, with a maximum power factor of 0.8 in overexcitation and 0.98 in under excitation, respectively.

Finally, starting from the PS active-reactive power measurements, the corresponding 8760 CHP capability curves are drawn to find the flexibility made available from CHP. Fig. 4 reports in green the boundary of the as-is PS yearly capability curve and in red the as-is PV flexibility.

Hydro power plants

A similar approach to CHP has been implemented to estimate the available hydropower plants' flexibility. As for CHP, a statistical analysis has evaluated the hourly power production based on real data of several MV and LV hydropower plants currently connected to the Unareti distribution network to find a standard yearly production trend. While real data are the blue dots in Fig. 5, the fifth-degree polynomial curve computed by interpolating the hydropower plants' P.U. hourly production is reported in red. Equation (2) is the fitting curve:

$$y = -4{,}37e^{-19}x^5 + 1{,}08e^{-14}x^4 - 9{,}85e^{-11}x^3 +$$

$$3{,}96e^{-7}x^2 - 6{,}35e^{-4}x + 0{,}632 \quad (2)$$

where:

- y is the power production in P.U. of the nominal power;
- x is the considered hour.

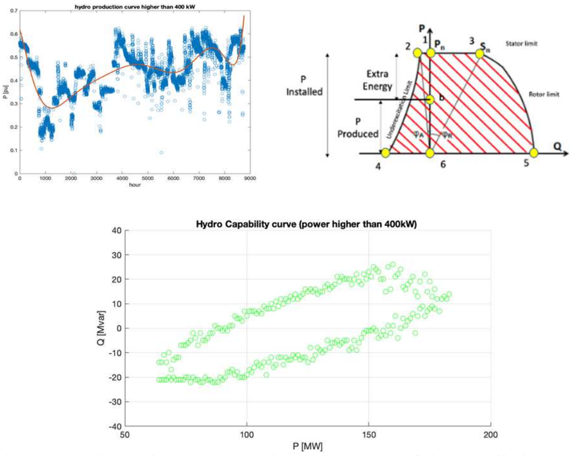


Fig. 5. Hourly Hydro power production in P.U. of the installed capacity (upper left picture); CEI 0-16 standard capability curve considered for hydro (upper right picture); boundaries of the as-is PS yearly capability curve in green (lower picture).

Fig. 5 clearly shows that hydropower plants' production follows the water availability, which increases at the winter season's end. Once the yearly trend is estimated, the same capability curve and almost the same approach used for CHP are applied to each hourly power production. The only additional assumption is that the hydropower plants are run-of-the-river hydroelectricity; therefore, the active power produced depends on water availability. Thus, it is assumed that the plants cannot exploit extra active power, i.e., $P_{upward}=0$.

Finally, starting from the PS active-reactive power measurements, the corresponding 8760 hydropower plants' capability curves are drawn to find the flexibility made available by hydropower plants. It is worth noting that, Fig. 5, only shows the limit of the PS as-is annual capacity curve in green. In fact, the little hydroelectric power available downstream of the PS Sud, only 420 kW, cannot guarantee a potentially interesting value of flexibility to a load far greater than the current hydroelectric power.

Electric Vehicles

The contribution of EVs has been estimated using the information and data contained in [35]. Authors in [35] propose four hourly charge profiles of EVs, which differ depending on where recharging takes place: home, work, B2C (Business Activity), and public. Moreover, the proposed curves distinguish between a working day and a weekday. Since nowadays, the EVs are still few in Milan, their contribution is taken into account only in the 2030 scenario. In the Developing Plan [33], Unareti foresees 204,000 EVs in 2030, and demand is estimated to be 340 GWh annually.

Once the yearly trend is obtained, the EVs capability curve reported in Fig. 6 is applied to each hourly power. On the one hand, it is assumed that all public and work-related charging points will be equipped with V2G technology, thus exploiting all four quadrants. On the other hand, it is supposed that home charging does not allow the reverse of the energy flow: in this case, the grid only sees the EVs as a load. Moreover, the apparent nominal power is assumed to be equal to the active power required in a specific hour, and point 1 to be the P-Q measured value in PS, supposing that the current contribution of EVs on PS active and reactive power is negligible.

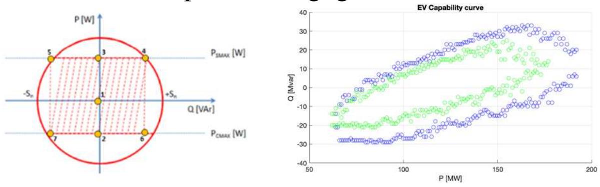


Fig. 6. CEI 0-16 standard BESS capability curve considered as EVs capability curve (left picture); boundaries of the as-is PS yearly capability curve in green, and considering the 2030 scenario EVs flexibility in blue (right picture).

C. *Resulting PS aggregated DERs flexibility assessment*

The procedure's last step aims to compute the aggregated DERs flexibility at the PCC between the transmission and the distribution network in the as-is and 2030 scenarios. The following Table II reports the expected DERs deployment downstream of the PS Sud within 2030.

TABLE. II
PS SUD INSTALLED CAPACITY IN THE AS-IS AND 2030 SCENARIOS

Scenario	Installed capacity on MV/LV grid [MW]			
	PV	Biomass/ Biogas	Hydro	CHP
as-is	5	-	0,420	27
2030	16	-	0,420	29

Based on the National Trend (NT) Italia scenario [36], the PV installed capacity should increase in the service area of the PS Sud by 11 MW before 2030. Instead, based on Unareti scenario, deployment of an additional 2 MW of CHP is expected [33]. On the other hand, no new installation of hydro and biomass/biogas is envisaged.

Fig. 7 summarizes the simulation results. Starting from the as-is PS Sud capability curve, in green, the resulting DERs flexibility is highlighted in red for the as-is scenario and blue for the 2030 ones.

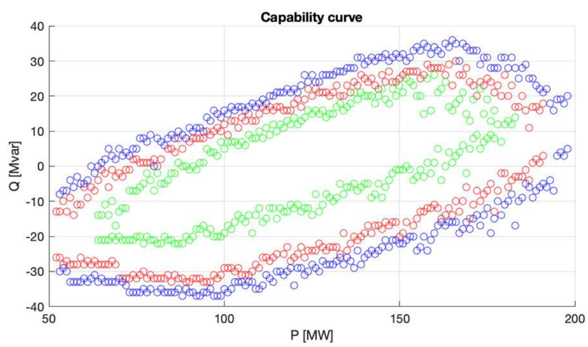


Fig. 7. Boundaries of the as-is PS yearly capability curve (in green), considering the as-is flexibility (in red) and the 2030 scenario flexibility (in blue).

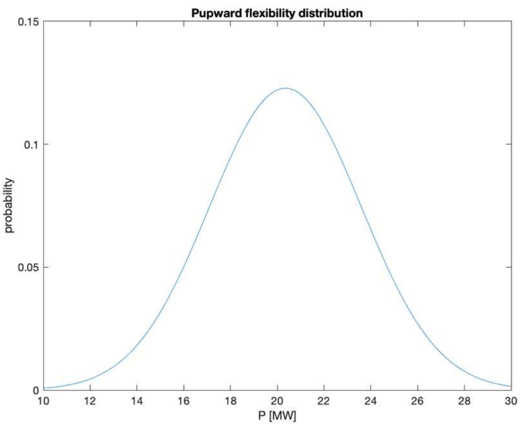
Looking at Fig. 7, it can be easily seen that there is already consistent potential flexibility, which is expected to rise in 2030. A significant additional contribution to upward and downward active power flexibility will be available thanks to the foreseen installation of new PV and EVs. Moreover, a proportional increase in upward and downward reactive power flexibility is expected.

III. Assessment of PS Sud potential contribution to transmission network contingency relieve

This last section aims at assessing the potential contribution of DERs flexibility in relieving voltage and current contingency on the HV grid. Based on transmission network analysis and operation evidence in the area of Milan, it is determined that meaningful values of flexibility to relieve HV transmission network constraints are at least either 10 MW or 10 Mvar. In general 10 MW variation brings to an appreciable variation of the line's power flows departing from the PS Sud, while 10 Mvar can be able to vary the voltage at the PS Sud of about 0.5 kV.

To better determine if DERs installed in the Milan area could help manage transmission grid issues, Fig. 8 reports the normal distribution related to the computed P_{upward} and $P_{downward}$ values in the 2030 scenario. On the one hand, the simulation suggests an average upward active power of about 20 MW, varying in the range 10 MW-30 MW. On the other hand, a more limited downward contribution is expected: 17 on average, ranging from 0 to -30 MW.

Regarding reactive power, instead, it is expected a pretty stable Q_{upward} of 35 Mvar and a $Q_{downward}$ of 25 Mvar. Thus, the outcomes of the simulations suggest that DERs installed on the distribution network could contribute to a better transmission network operation, and help in managing voltage and power flow issues.



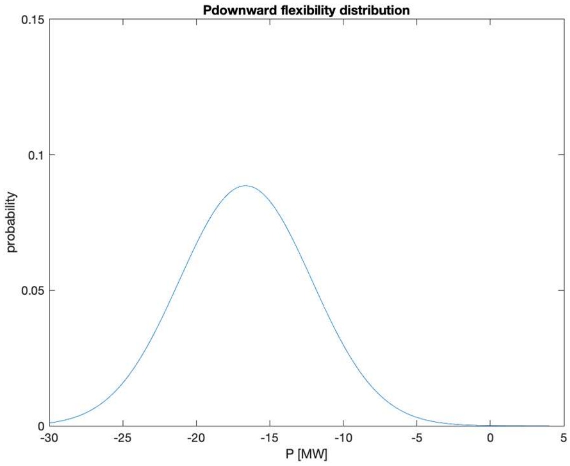
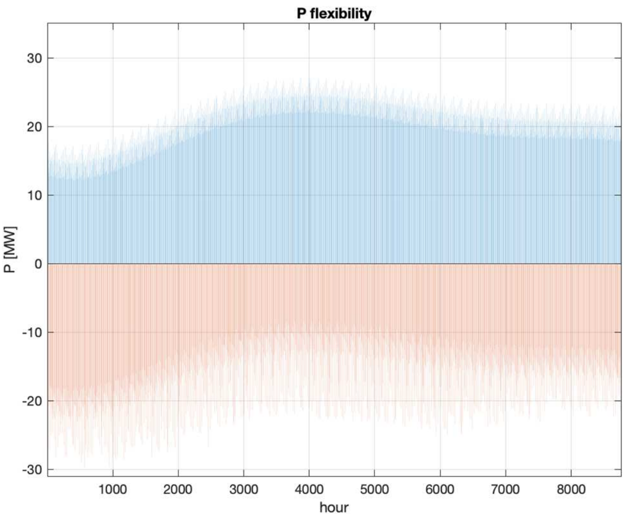


Fig. 8. Normal probability distribution in 2030 scenario: P_{upward} (upper picture) and $P_{downward}$ (lower picture).

Fig. 9 shows the hourly trend of the active and reactive flexibility, upward in blue and downward in red, for the 2030 scenario. Regarding active power, during summer months, upward flexibility has a large contribution, mainly related to the flexibility provided by CHPs. On the one hand, during winter months, CHPs operate at higher power to satisfy the greater thermal demand, so upward flexibility from the operating point to the install capacity is reduced. On the other hand, in the warmer months, when the heating demand is lower, CHPs operate less, making available a more significant potential upward flexibility. Vice versa works for downward flexibility, potentially higher in winter months and more down in warmer ones.

Regarding reactive power, the potential flexibility is stable, predominating upward rather than downward.



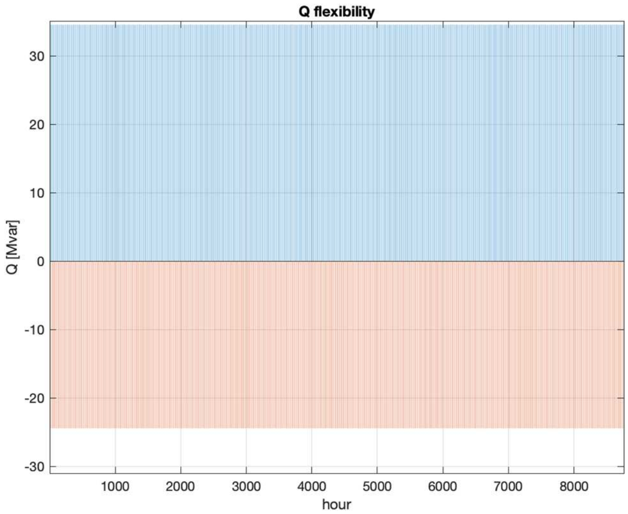


Fig. 9. Trend of hourly P_{upward} and $P_{downward}$ (upper picture) and Q_{upward} and $Q_{downward}$ (lower picture) in the 2030 scenario.

As an additional outcome, Fig. 10 reports the availability of active power flexibility during daytime and night hours in the form of maximum upward and downward for each day. It can be observed that the downward PV contribution is more relevant during the daytime and especially during the summer months when the contribution of CHPs is reduced. During night hours, there is no contribution of PV, and therefore flexibility remains mainly linked to CHPs and EVs.

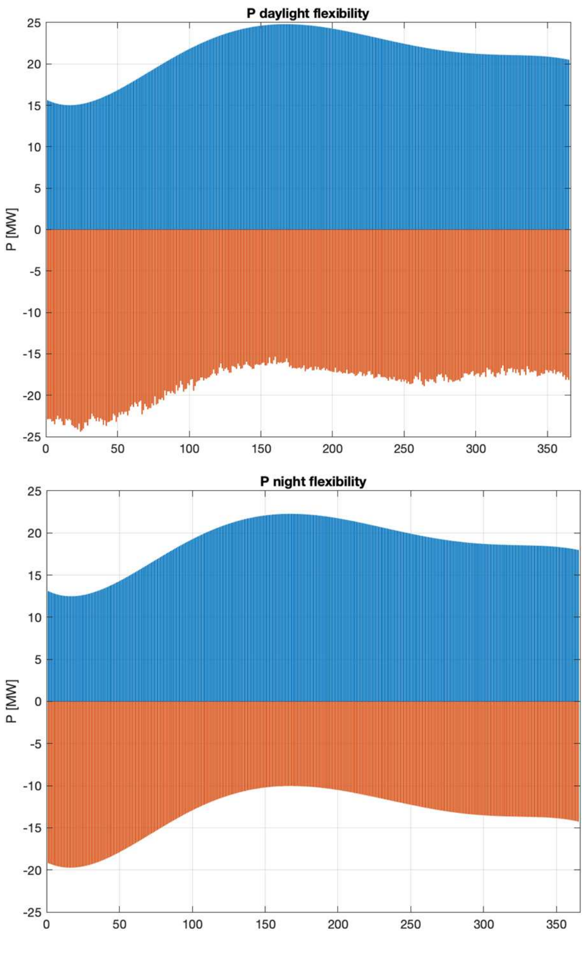


Fig. 10. Trend of daily maximum P_{upward} and $P_{downward}$ during daylight hours (upper picture) and night hours (lower picture) in the 2030 scenario.

Moreover, considering the daily values, the box plots reported in Fig. 11 can be set up. The upward flexibility has a narrow gap between minimum and maximum values and even between the first and the third quartile: we can conclude that upward flexibility is more predictable than downward ones, probably due to the downward flexibility related to the stochastic behavior of PV. Moreover, it is worth noticing that downward flexibility shows several outliers during the winter months, making a prediction of the power available for flexibility again more complicated.

A similar analysis on reactive power flexibilities is not reported due to pretty constant values throughout the year.

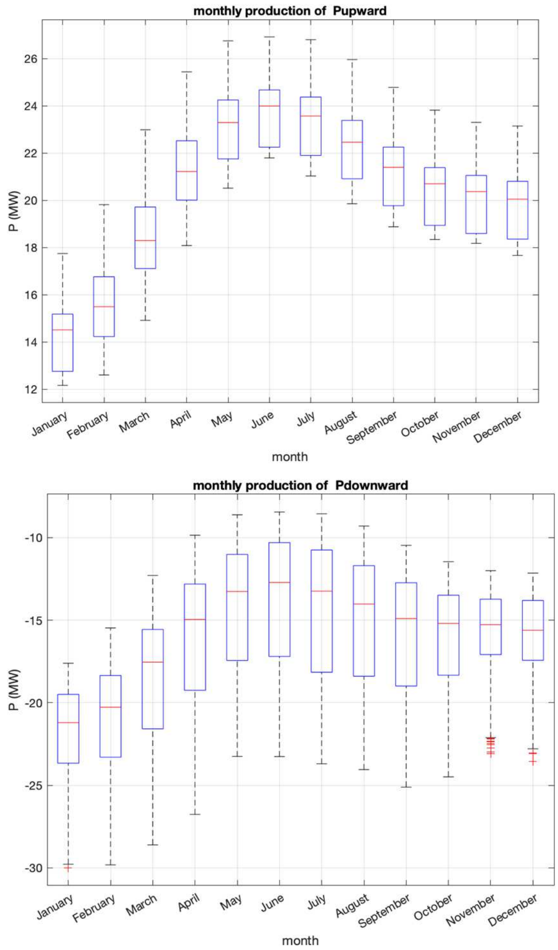


Fig. 11. Monthly P_{upward} (upper picture) and $P_{downward}$ (lower picture) in 2030 scenario.

Finally, the graphs reported in Fig. 12 show a typical trend of P_{upward} for a sample day, i.e., September 4th 2022. It is possible to observe that the flexibility is greater during daylight hours, with a steep ramp and a peak around 10 A.M. and a second smaller peak around 9:00 P.M.. This is another interesting outcome of the analysis. In fact, the time of higher DERs upward flexibility seems to match with the time of higher demand, making the flexibility a valuable tool to smooth the load demand curve and help in relieving potential network contingencies.

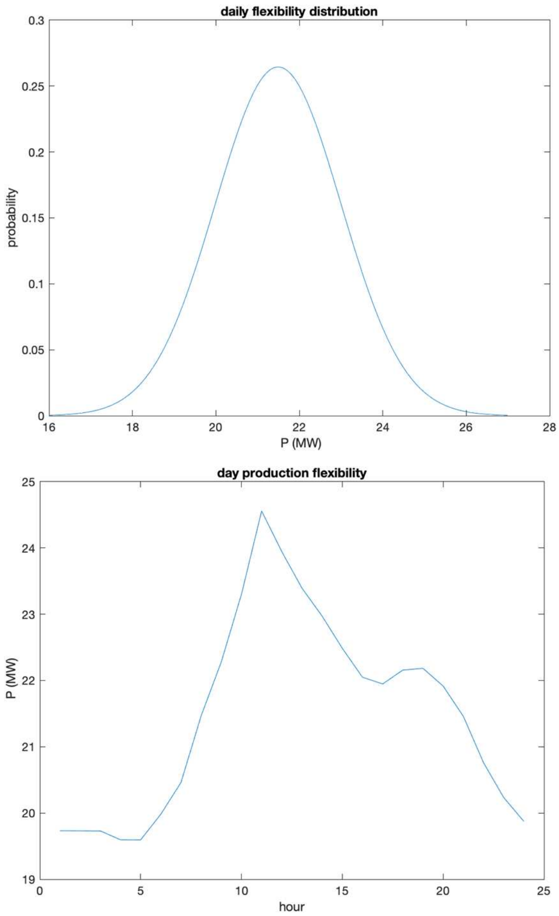


Fig. 12. P_{upward} daily normal probability distribution (upper picture) and hourly trend (lower picture) in the 2030 scenario.

IV. CONCLUSION

This paper proposes a feasibility study of TSO-DSO coordination which allows using DERs to solve transmission network criticalities, both in operational and short- to medium-term time horizons, without involving the exchange of sensitive information between the two utilities. A detailed analysis has been carried out on the available flexibility of DERs active and reactive power. The results obtained show that aggregated DERs under the PS Sud, used as a case study, can provide an interesting degree of flexibility to the TSO. In particular, DERs could be used to control the HV bus voltage through a substantial variation in reactive power to be fed into or absorbed by the transmission grid. DERs can also be helpful in terms of active power: they could help the TSO by limiting the active power production or, vice versa, by increasing the output to reduce the power flow from the transmission to the distribution network. As a future development, additional simulations can be easily carried out, including other possible DERs: storage systems, static synchronous compensator, and tap-changer of HV/MV transformers installed in PS, distribution network reconfiguration. Moreover, the distribution network constraints can be also taken into account to verify the required flexibility would be exploited without any network violations. Regarding the issue of data exchange and the TSO's visibility over the downstream DSO networks instead, nowadays, the TSO only observes power exchanges between the transmission grid and each PS, but this information is no longer sufficient for an efficient integrated transmission and distribution network planning process and to understand the dynamics of events in real-time, to adopt the most effective and efficient countermeasures. Enhancing the observability of the DSO grid would lead to improvements in many applications used for the planning and secure management of the transmission network by Terna.

REFERENCES

[1] A. Bosisio, A. Berizzi, A. Morotti, G. Iannarelli, B. Greco, and C. Boccaletti, “A GIS-based approach to assessing large-scale building-integrated photovoltaic generation: a case study of Milan, Italy,” in *2022 AEIT International Annual Conference (AEIT)*, 2022, pp. 1–6. doi: 10.23919/AEIT56783.2022.9951760.

[2] G. Iannarelli, A. Cirocco, B. Greco, C. Moscatiello, A. Bosisio, and C. Boccaletti, “Management strategy of EV fleets charging stations for demand response capabilities: a case study,” in *2022 AEIT International Annual Conference (AEIT)*, 2022, pp. 1–6. doi: 10.23919/AEIT56783.2022.9951728.

[3] R. Faranda, L. Gozzi, A. Bosisio, and K. Akkala, “SCADA system for optimization of energy exchange with the BESS in a residential case,” in *Proceedings - 2019 IEEE International Conference on Environment and Electrical Engineering and 2019 IEEE Industrial and Commercial Power Systems Europe, EEEIC/I and CPS Europe 2019*, 2019. doi: 10.1109/EEEIC.2019.8783941.

[4] C. Mosca *et al.*, “Mitigation of frequency stability issues in low inertia power systems using synchronous compensators and battery energy storage systems,” *IET Generation, Transmission & Distribution*, vol. 13, no. 17, pp. 3951–3959, Sep. 2019, doi: 10.1049/IET-GTD.2018.7008.

[5] G. Iannarelli, A. Bosisio, B. Greco, C. Moscatiello, and C. Boccaletti, “Flexible resources dispatching to assist DR management in urban distribution network scenarios including PV generation: An Italian case study,” in *Proceedings - 2020 IEEE International Conference on Environment and Electrical Engineering and 2020 IEEE Industrial and Commercial Power Systems Europe, EEEIC / I and CPS Europe 2020*, Institute of Electrical and Electronics Engineers Inc., Jun. 2020. doi: 10.1109/EEEIC/ICPSEUROPE49358.2020.9160856.

[6] CEDEC, EDSO, entsoe, Eurelectric, and GEODE, “General guidelines for reinforcing the cooperation between TSOs and DSOs.” https://eepublicdownloads.entsoe.eu/clean-documents/Publications/Position%20papers%20and%20reports/entsoe_pp_TSO-DSO_web.pdf (accessed Feb. 22, 2023).

[7] T. Alazemi, M. Darwish, and M. Radi, “TSO/DSO Coordination for RES Integration: A Systematic Literature Review,” *Energies (Basel)*, vol. 15, no. 19, p. 7312, Oct. 2022, doi: 10.3390/en15197312.

[8] European Parliament and Council, “Directive (EU) 2019/944 of the European Parliament and of the Council

of 5 June 2019 on common rules for the internal market for electricity and amending Directive 2012/27/EU (recast) (Text with EEA relevance.).” https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=celex%3A32019L0944 (accessed Dec. 09, 2022).
[9] European Parliament and Council, “Fit for 55 - The EU’s plan for a green transition.” https://www.consilium.europa.eu/en/policies/green-deal/fit-for-55-the-eu-plan-for-a-green-transition/ (accessed Jan. 09, 2023).
[10] Terna S.p.A., “Italian Grid Code.” https://www.terna.it/en/electric-system/grid-codes/italian-grid-code (accessed Dec. 07, 2022).
[11] Y. Liu and L. Wu, “Integrating Distributed Energy Resources into the Independent System Operators’ Energy Market: a Review,” *Current Sustainable/Renewable Energy Reports*, vol. 8, no. 4, pp. 233–241, 2021, doi: 10.1007/s40518-021-00190-8.
[12] A. G. Givisiez, K. Petrou, and L. F. Ochoa, “A Review on TSO-DSO Coordination Models and Solution Techniques,” *Electric Power Systems Research*, vol. 189, p. 106659, 2020, doi: https://doi.org/10.1016/j.epsr.2020.106659.
[13] A. Bytyqi, S. Gandhi, E. Lambert, and N. Petrovič, “A Review on TSO-DSO Data Exchange, CIM Extensions and Interoperability Aspects,” *Journal of Modern Power Systems and Clean Energy*, vol. 10, no. 2, pp. 309–315, 2022, doi: 10.35833/MPCE.2021.000770.
[14] M. Khojasteh, P. Faria, F. Lezama, and Z. Vale, “A hierarchy model to use local resources by DSO and TSO in the balancing market,” *Energy*, vol. 267, p. 126461, 2023, doi: https://doi.org/10.1016/j.energy.2022.126461.
[15] S. I. Vagropoulos, P. N. Biskas, and A. G. Bakirtzis, “Market-based TSO-DSO coordination for enhanced flexibility services provision,” *Electric Power Systems Research*, vol. 208, p. 107883, 2022, doi: https://doi.org/10.1016/j.epsr.2022.107883.
[16] A. Papalexopoulos, R. Frowd, and A. Birbas, “On the development of organized nodal local energy markets and a framework for the TSO-DSO coordination,” *Electric Power Systems Research*, vol. 189, p. 106810, 2020, doi: https://doi.org/10.1016/j.epsr.2020.106810.
[17] A. Vicente-Pastor, J. Nieto-Martin, D. W. Bunn, and A. Laur, “Evaluation of flexibility markets for retailer-dso-tso coordination,” *IEEE Transactions on Power Systems*, vol. 34, no. 3, pp. 2003–2012, 2019, doi: 10.1109/TPWRS.2018.2880123.
[18] M. Usman, M. I. Alizadeh, F. Capitanescu, I.-I. Avramidis, and A. G. Madureira, “A novel two-stage TSO–DSO coordination approach for managing congestion and voltages,” *International Journal of Electrical Power and Energy Systems*, vol. 147, 2023, doi: 10.1016/j.ijepes.2022.108887.
[19] J. Ringelstein, M. Vogt, A. M. Khavari, R. Ciavarella, M. di Somma, and G. Graditi, “A methodology for improved TSO-DSO coordination in grid operation planning,” *Electric Power Systems Research*, vol. 211, p. 108445, 2022, doi: https://doi.org/10.1016/j.epsr.2022.108445.
[20] M. Resener, B. Venkatesh, B. M. P. Ferraz, S. Haffner, A. Balbinot, and L. A. Pereira, “MILP Model for Optimal Day-Ahead PDS Scheduling Considering TSO-DSO Interconnection Power Flow Commitment Under Uncertainty,” *IEEE Transactions on Power Systems*, pp. 1–14, 2022, doi: 10.1109/TPWRS.2022.3228838.
[21] R. Dzikowski, “DSO-TSO coordination of day-ahead operation planning with the use of distributed energy resources,” *Energies (Basel)*, vol. 13, no. 14, 2020, doi: 10.3390/en13143559.
[22] C. Mosca *et al.*, “Technical and Economic Impact of the Inertia Constraints on Power Plant Unit Commitment,” *IEEE Open Access Journal of Power and Energy*, vol. 7, pp. 441–452, 2020, doi: 10.1109/OAJPE.2020.3029118.
[23] G. Celli, F. Pilo, G. Pisano, S. Ruggeri, and G. G. Soma, “Risk-oriented planning for flexibility-based distribution system development,” *Sustainable Energy, Grids and Networks*, vol. 30, p. 100594, 2022, doi: https://doi.org/10.1016/j.segan.2021.100594.
[24] J. Liu, L. Zhang, K. Liu, Z. Tang, P. P. Zeng, and Y. Li, “To exploit the flexibility of TSO–DSO interaction: A coordinated transmission robust planning and distribution stochastic reinforcement solution,” *Energy Reports*, vol. 9, pp. 27–36, 2023, doi: https://doi.org/10.1016/j.egyr.2022.10.368.
[25] E. F. Alvarez, L. Olmos, A. Ramos, K. Antoniadou-Plytaria, D. Steen, and L. A. Tuan, “Values and impacts of incorporating local flexibility services in transmission expansion planning,” *Electric Power Systems Research*, vol. 212, p. 108480, 2022, doi: https://doi.org/10.1016/j.epsr.2022.108480.
[26] N. R. Perez *et al.*, “ICT architectures for TSO-DSO coordination and data exchange: a European perspective,” *IEEE Trans Smart Grid*, p. 1, 2022, doi: 10.1109/TSG.2022.3206092.
[27] M. Radi, G. Taylor, J. Cantenot, E. Lambert, and N. Suljanovic, “Developing Enhanced TSO-DSO Information and Data Exchange Based on a Novel Use Case Methodology,” *Front Energy Res*, vol. 9, 2021, doi: 10.3389/fenrg.2021.670573.
[28] S. Skok, A. Mutapčić, R. Rubesa, and M. Bazina, “Transmission power system modeling by using aggregated distributed generation model based on a TSO—DSO data exchange scheme,” *Energies (Basel)*, vol. 13, no. 15, 2020, doi: 10.3390/en13153949.
[29] C. Mosca *et al.*, “A new real-time approach for the load forecasting in the operation of sub-transmission systems,” in *2019 AEIT International Annual Conference (AEIT)*, 2019, pp. 1–6. doi: 10.23919/AEIT.2019.8893398.
[30] Comitato Elettrotecnico Italiano (CEI), “CEI-016 standard.” Accessed: Jan. 09, 2023. [Online]. Available: https://www.ceinorme.it/strumenti-online/norme-cei-0-16-e-0-21/
[31] Comitato Elettrotecnico Italiano (CEI), “CEI 0-21 standard.” Accessed: Jan. 09, 2023. [Online]. Available: https://www.ceinorme.it/strumenti-online/norme-cei-0-16-e-0-21/
[32] A. Bosisio, D. D. Giustina, S. Fratti, A. Dede, and S. Gozzi, “A metamodel for multi-utilities asset management,” in *2019 IEEE Milan PowerTech, PowerTech 2019*, 2019. doi: 10.1109/PTC.2019.8810812.
[33] UNARETI S.p.A., “Piano di Sviluppo e Incremento resilienza,” 2021. https://www.unareti.it/unr/unareti/elettricita/cittadini/piano-di-sviluppo-e-incremento-resilienza/ (accessed Feb. 16, 2021).
[34] European Commission, “Photovoltaic Geographical Information System (PVGIS).” https://re.jrc.ec.europa.eu/pvg_tools/en/ (accessed Jan. 09, 2023).

[35] G. Rancilio, F. Bovera, and M. Delfanti, "Tariff-based regulatory sandboxes for EV smart charging: Impacts on the tariff and the power system in a national framework," *Int J Energy Res*, vol. 46, no. 11, pp. 14794–14813, Sep. 2022, doi: 10.1002/ER.8183.

[36] Terna spa, "Scenarios." https://www.terna.it/it/sistema-elettrico/rete/piano-sviluppo-rete/scenari (accessed Jan. 09, 2023).