DIRECTORATE GENERAL FOR NEIGHBOURHOOD AND ENLARGEMENT NEGOTIATIONS – DG NEAR

Short Term High Quality Studies to Support Activities under the Eastern Partnership

HIQSTEP PROJECT

STUDY ON THE EFFECT OF THE PLACEMENT OF SOLAR PANELS ON BUILDINGS TO INCREASE ENERGY SECURITY AND ENERGY EFFICIENCY AND DEVELOP CLEAN ENERGY IN THE EASTERN PARTNERSHIP COUNTRIES

Component 5 Report: Programme Development for Building-PVs Based on a Cost-Benefit Analysis: Armenia, Azerbaijan, Belarus, Moldova and Ukraine

November 2017

List of abbreviations

AM	Armenia
ANRE	The National Regulatory Authority for Energy in Moldova
AREA	Azerbaijan State Agency on Alternative and Renewable Energy Sources
AZ	Azerbaijan
BY	Belarus
CBA	Cost Benefit Analysis
CEER	Council of European Energy Regulators
DANIDA	Danish International Development Agency
DGPV	Distributed Generation from Photovoltaics
DISCO	Distribution Company
DSO	Distribution System Operator
EaP	Eastern Partnership
EBGL	Electricity Balancing Guideline
EC	European Commission
ECT	Energy Community Treaty
ESCO	Electricity System Commercial Operator of Georgia
EU	European Union
EUD	EU Delegation
FiP	Feed in Premium
FiT	Feed in Tariff
GE	Georgia
GEDF	Georgian Energy Development Fund
GWNERC	Georgian Water and Energy Regulatory Commission
HiQSTEP	Short term high quality studies to support activities under the Eastern Partnership
IRR	Internal Rate of Return
LCOE	Levelised Cost of Energy
MD	Moldova
MS	Member State
NEURC	National Energy and Utilities Regulatory Commission of Ukraine
NM	Net Metering
NM	Net Metering
PSRC	Public Services Regulatory Commission of the Republic of Armenia
PV	Photovoltaic(s)
R2E2	Armenia Renewable Resources and Energy Efficiency Fund
RES	Renewable Energy Sources
ROO	Renewable Obligation Order
SAEEE	State Agency on Energy Efficiency and Energy Saving of Ukraine
SPE	Solar Power Europe
STL	Study Team Leader
T&D	Transmission and Distribution
TOR	Terms of Reference
TSO	Transmission System Operator
TYNDP	Ten Year Network Development Plan
UA	Ukraine
VRE	Variable Renewable Electricity
WACC	Weighted Average Cost of Capital

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1 Preamble

The present report is a deliverable of the "Study of the Effect of the Placement of Solar PVs on Buildings in the EaP Countries" carried in the framework of the EU-funded project "High Quality Studies to Support Activities under the Eastern Partnership - HiQSTEP" (EuropeAid/132574/C/SER/Multi). The study covers all six Eastern Partner Countries, namely Armenia, Azerbaijan, Belarus, Georgia, Moldova and Ukraine.

The overall objective of the study is to address the effect of the placement of solar panels on buildings in Eastern Partner countries for the purpose of increasing energy security and energy efficiency and developing clean energy sources.

The specific objectives of the study are the following:

- To present EU policies, rules, regulations, tools and schemes towards the promotion of solar panels on buildings;
- To assess existing policies, rules, regulations and tools towards promotion of solar panels on buildings in the six Eastern Partner countries;
- To develop cost-benefit analysis for the staged development of building PVs in all Eastern Partner countries;
- To formulate recommendations on how to enhance PV penetration in the six Eastern Partners;
- To quantify the impact of building PV penetration to the overall energy mix and on the energy security of each country and to quantify the impact of PV generated energy to greenhouse gas emission reduction.

The present Study was implemented by a Study Team headed by Mr. Nikos Tourlis, Study Team Leader and composed of:

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Special thanks to the Study's counterparties in the Eastern Partner Countries for their support and useful guidance throughout the elaboration of the study including the field missions. In particular the Study Team wishes the best with the future implementation of buildings' solar PV programmes to:

- The Ministry of Energy and Natural Resources of Armenia, represented by Mr. Tigran Melkonyan;

- The Agency for Renewable Energy of Azerbaijan (AREA), represented by Mr. Jamil Malikov;
- The Department of Energy Efficiency in National Standardisation Authority of Belarus, represented by Mr. Andrey Minekov and Mr. Vladimir Shevchenok;
- The Ministry of Energy of Georgia, represented by Ms. Margalita Arabidze and Ms. Natali Jamburia;
- The Ministry of Economy of Moldova, represented by Mr. Denis Tumuruc;
- The State Agency for Energy Efficiency of Ukraine (SAEE), represented by Mr. Sergeiy Savchuk;

2 Introduction

The aim of this fifth component of the solar power in buildings study is to develop and undertake a cost benefit analysis of different scenarios, allowing for a staged building-PVs installation programme, accounting for different levels of PV penetration and policy support in selected Eastern Partner Countries (Armenia, Azerbaijan, Belarus, Moldova and the Ukraine).

The analysis undertaken in the Component 2: "Review of Eastern Partner Countries experience with building-PVs" report of this study has concluded that the current situation in those countries with respect to energy services, RES and (in particular) PV markets surely varies from country to country whereas overall it is rather in its early stages of development. There are differences - as it was also discussed in detail in the "Review of Eastern Partner Countries experience with building-PVs" report - with respect to the technological, regulatory and financing background, but even in Ukraine, where PV deployment is comparatively more advanced, the market is still not developed in its full potential. Moreover, as the gap analysis in the "Review of Eastern Partner Countries experience with building-PVs" report of this study has highlighted, the current framework for RES systems is cumbersome and not particularly favourable for the development of distributed generation, taking also into account the fact that the Net Metering regulations are rather unattractive, due to the prevailing low electricity prices in the region.

The purpose of this study is to analyse and assess the level at which building-PV deployment could accrue in the years to come and under which policy and regulatory conditions this can happen. Therefore, building-PV penetration scenarios were developed based on the "Quantification of the potential of building-PVs in Georgia and the rest of the Eastern Partner countries" report (Component 3) for major cities in each country. Those deployment scenarios are associated with the implementation of a building-PV specific policy support, in the form of either capital grant (coupled with a net metering scheme) or a Feed in Tariff (FIT) scheme. Alternative and more competitive support mechanisms e.g. Feed-in Premiums potentially based on an auction scheme are not considered in this study due to the transitional phase of the electricity markets in the countries under consideration. A cost and benefits analysis of the implementation of the deployment scenarios is then undertaken in relation to increasing levels of PV policy support in order to provide evidence and support to possible policy decisions.

Section 3 in this report sets the context of the cost benefit analysis by defining the target market segments and by developing scenarios for building-PV deployment, associated with a progressive introduction of PV policy support measures. Section 3.1 takes outcomes of the "Quantification of the potential of building-PVs in Georgia and the rest of the Eastern Partner countries" report of this study, in terms of potential PV capacity on buildings, as the starting point to develop scenarios for building-PV deployment for the targeted cities in each one of the five countries and at national aggregated level. Targets are defined for the market segments, based on evidence of installation patterns in other EU countries, which experienced a documented, successful PV market uptake. Section 3.2 presents the results of the scenarios build up for building-PV deployment and combines them with a progressive introduction of policy support tools for each country separately. These scenarios constitute the basis and reference for both end users and cost-benefits analysis in the following sections.

Section 4 consists of two parts: In Section 4.1 main assumptions, data and results of the end user analysis are presented for each country and for the two market segments assumed: residential and non-residential. A typical financial cash flow analysis of building-PV investment in each market segment has been conducted, in order to identify the Internal Rate of Return (IRR). In Section 4.2 results of end user analysis are presented together with the estimates for the level of policy support needed in order to make the investment profitable enough to incentivise the deployment of building-PV.

Section 5 presents respectively assumptions, data and results of the cost and benefit analysis of the policy measures assumed under the different building-PV deployment scenarios, accounting for both the cost of policy (both at an aggregate system's level and in terms of its impact on electricity consumers) and the quantifiable benefits accruing from the implementation of building-PV capacity in the country.

Section 6 presents a qualitative evaluation of the possible impact of penetration of building-PV on the grid and its possible implications for the electricity system of the five countries considered. It is based on the review of EU experiences, but also on detailed grid data from Moldelectrica, the Moldovan TSO. These data enabled us to develop a better understanding on the hosting capacity issues for Moldova (compared to the remainder EaP countries) both at aggregated system and at city's level. Therefore, the Moldovan results are presented in greater detail, being a showcase example for the nature of the assessment required to be performed for all countries.

Section 7, finally, concludes and provides final recommendations on next steps for the deployment of building-PV sector in the five countries.

3 Defining building-PV deployment scenarios for cost benefit analysis

This section sets the context for cost benefit analysis of staged deployment of building-PV in Armenia, Azerbaijan, Belarus, Moldova and Ukraine. Methods used and several assumptions taken are in common with those of the cost benefit analysis of building-PV deployment in Georgia carried out in Component 4: “Programme development for building-PVs based on a Cost-Benefit Analysis: Georgia” report of this study. Thus, for the purpose of avoiding duplications, we would often refer to this report for further details on methods and assumptions. In later on in this section we define, for each EaP country, the staged building-PV deployment scenarios based on total PV capacity potential as estimated in Component 3: “Quantification of the potential of building-PVs in Georgia and the rest of the Eastern Partner countries” report of this study, for different building-PV market segments and as a function of progressive introduction of PV policy measures. The ultimate goal is to develop an educated estimate on the optimal level of support required for the expansion of the national building-PV market in each EaP country.

3.1 Defining total building-PV capacity potential and market segments

Staged building-PV deployment scenarios for Armenia, Azerbaijan, Belarus, Moldova and Ukraine are developed based on the total installation potential for building-PV as estimated for each country in Component 3: “Quantification of the potential of building-PVs in Georgia and the rest of the Eastern Partner countries” report of this study. This potential has been estimated in terms of MWp of rooftop PV systems which can be installed on suitable building roofs for major cities of each country. Estimates are developed for two main typologies of buildings: 1. Single family houses, characterised by sloped roofs; 2. Large buildings, characterised by flat roofs. The resulting estimates of building-PV capacity potential for each country are presented in Table 1 to Table 5 below.

A constraint factor of 80% has been applied to the overall total PV capacity of single family houses/sloped roof building type to take into account significant restrictions to the PV installation potential due to the limited bearing capacity of the roofs, the lack of adequate structural support and the difficulty in ensuring effective water tightness (for more details please see “Programme development for building-PVs based on a Cost-Benefit Analysis: Georgia” report of this study) but also the difficulties pertinent to access to finance which are most frequent for this specific market segment. In other words, the constrained capacity potential cannot exceed 20% of the total capacity estimated. Therefore the estimates for building-PV capacity potential used for the purposes of the scenario building (in Section 3.2) are those the highlighted third and fifth columns in Table 1 to Table 5 below , i.e. *Flat roof PV capacity and “Constrained” sloped roof capacity*.

Table 1: Maximum building-PV capacity potential, for sloped roof and flat roof buildings - Armenia

City	Sloped roof PV capacity (MWp)	Flat roof PV capacity (MWp)	Total potential PV capacity (MWp)	“Constrained” Sloped roof PV capacity (MWp)	Total “Constrained” Potential PV capacity (MWp)
Yerevan	1388	385	1772	277	662
Vanazdor	233	62	295	46	109
Gyumri	193	51	244	38	90
Total	1813	498	2312	363	861

Table 2: Maximum building-PV capacity potential, for sloped roof and flat roof buildings - Ukraine

City	Sloped roof PV capacity (MWp)	Flat roof PV capacity (MWp)	Total potential PV capacity (MWp)	"Constrained" Sloped roof PV capacity (MWp)	Total "Constrained" Potential PV capacity (MWp)
Kyiv	3983	488	4471	979	1285
Odessa	2940	322	2362	408	730
Lviv	599	142	741	120	262
Zaporizhia	524	236	761	105	341
Total	7146	1189	8335	1324	2513

Table 3: Maximum building-PV capacity potential, for sloped roof and flat roof buildings - Moldova

City	Sloped roof PV capacity (MWp)	Flat roof PV capacity (MWp)	Total potential PV capacity (MWp)	"Constrained" Sloped roof PV capacity (MWp)	Total "Constrained" Potential PV capacity (MWp)
Chisinau	143	29	172	29	58
Balti	17	3	21	4	7
Cahul	4	1	5	1	2
Total	165	34	199	33	67

Table 4: Maximum building-PV capacity potential, for sloped roof and flat roof buildings - Belarus

City	Sloped roof PV capacity (MWp)	Flat roof PV capacity (MWp)	Total potential PV capacity (MWp)	"Constrained" Sloped roof PV capacity (MWp)	Total "Constrained" Potential PV capacity (MWp)
Minsk	2032	341	2373	406	748
Mogilev	538	72	611	108	180
Vitebsk	641	79	720	128	208
Total	3211	493	3704	642	1135

Table 5: Maximum building-PV capacity potential, for sloped roof and flat roof buildings - Azerbaijan

City	Sloped roof PV capacity (MWp)	Flat roof PV capacity (MWp)	Total potential PV capacity (MWp)	"Constrained" Sloped roof PV capacity (MWp)	Total "Constrained" Potential PV capacity (MWp)
Baku	2346	709	3055	469	1178
Sumgait	270	72	343	54	127
Ganja	232	61	294	47	108
Total	2849	842	3691	570	1412

The analysis is focused on two PV market segments defined as follows (for more details please refer to Component 4: "Programme development for building-PVs based on a Cost-Benefit Analysis: Georgia" report of this study):

- Residential: small PV systems owned by individuals/households;
- Non/residential: small to medium size PV systems owned by commercial actors/SMEs or the public sector. We define this segment non-residential, rather than just commercial, as it can include PV systems installed on public buildings. Public buildings are likely to be an interesting target for building-PV deployment as, in particular during the early stages of the PV market development, public authorities could play a leading-by-example role by installing PV systems on public premises. However, due to lack of specific data on public buildings, it has not been possible to differentiate the segment on its own and it has instead been merged together with commercial in a single non-residential market segment.

For the purpose of this analysis and the use of the total energy potential estimated in Component 3: "Quantification of the potential of building-PVs in Georgia and the rest of the Eastern Partner countries" report of this study, it is further assumed that small PV systems will be installed by individuals/households on the sloped roofs that characterise the single family houses, whereas larger investments in medium size PV systems are undertaken by commercial actors and public bodies on large buildings, characterised by flat roofs. In other words, maximum installation potential for the residential market segment is assumed to be equal to the "Constrained" sloped roof PV capacity and for the non-residential market segment equal to the Flat roofs PV capacity, as presented in highlighted third and fifth columns in Table 1 to Table 5 above.

3.2 Scenario building

In order to develop scenarios for building-PV deployment in Armenia, Azerbaijan, Belarus, Moldova and Ukraine we have firstly calculated a progressive deployment of the maximum estimated total capacity potential from 2018 up to 2030 for each market segment, as derived from Component 3: "Quantification of the potential of building-PVs in Georgia and the rest of the Eastern Partner countries" report of this study and presented in highlighted third and fifth columns in Table 1 to Table 5 above, i.e. *"Constrained" sloped roof* PV capacity for residential and *Flat roofs PV capacity* for the non-residential. To account for progressive maturity of respective national PV markets we assumed a staged implementation in each country, implying an initial slower deployment and a faster uptake at later stages (i.e. a learning curve); in particular we assumed that:

- 30% of the total potential will be deployed in the first half of the period (2018-2024),
- and the remaining 70% deployed between 2025 and 2030.

The analysis then focuses on the first 5 years, i.e. 2018-2022. On one hand we deemed rather unrealistic to reliably foresee future national PV markets development up to 2030; on the other we decided to focus the attention on designing policy support for early stage PV market development (see also discussion on policy instruments below and in Component 4: "Programme development for building-PVs based on a Cost-Benefit Analysis: Georgia" report of this study), which could then be followed by a new policy framework updated to account for the countries' PV market evolution in the first years.

We have developed scenarios of potential future building-PV penetration, assuming different levels of deployment over the 5 years' period of the total building-PV potential estimated for each city and in each country, in particular:

- a High Scenario which assumes that the total potential is actually achieved (to 100%);

- a Medium Scenario which assumes a 50% deployment.

Such different levels of deployment are assumed in relation to different levels of policy commitment to building-PV: i.e. the stronger the policy support, the more likely PV deployment is. In terms of building-PV policy support we consider and analyse the implementation of policy instrument over the 2018-2022 period (5 years) similar to those already implemented in other European countries at the early stages of their PV sector development (see also Component 4: "Programme development for building-PVs based on a Cost-Benefit Analysis: Georgia" report of this study for further discussion), in particular:

- Net metering scheme, as already in place in several countries (i.e. Moldova, Armenia and Ukraine);

- Capital grants, defined as a percentage of the initial building-PV investment cost;

- Feed in Tariff scheme (FiT) offering a specified generation tariff for the total PV electricity generated, over a 20-year timeframe.

The respective levels of support, i.e. the capital grant, as a percentage of the initial investment cost, and the tariff offered under FiT scheme are calculated in Section 4.2 through an investment appraisal analysis, which optimises policy support in order to achieve returns on the investment sufficient to incentivise end-users to invest in PV systems. The only exceptions to this methodology are Belarus and Azerbaijan, for which we have developed a unique building-PV deployment scenario which assume and analyse the implementation of a small, country specific pilot policy support programme. Later on, in this report the building-PV deployment scenarios and main policy assumptions are presented for each country.

3.2.1 Armenia

Table 6 and Table 7 below present staged building-PV deployment in the two stages (i.e. up to 2024 and up to 2030) and the annual building-PV installation target for each city and market segment over the 2018-2022 period (which constitutes the maximum deployment potential over the timeframe considered, i.e. the High Scenario deployment level), respectively.

Table 6: Armenia – staged deployment of maximum building-PV potential by 2030, MW

	2018-2024	2025-2030
Yerevan		
Residential	83	194
Non-residential	115	269
Vanazdor		
Residential	14	33
Non-residential	19	43
Gyumri		
Residential	12	27
Non-residential	15	36
Total	***258***	***603***

Note: 30% of total PV capacity 2018-2024; 70% of total PV capacity 2025-2030

Table 7: Armenia – building-PV installation target per city and market segment (equal to High Scenario), MW

	2018	2019	2020	2021	2022	Total over 5 years
Yerevan						
Residential	12	12	12	12	12	59
Non-residential	16	16	16	16	16	82
Vanazdor						
Residential	2	2	2	2	2	10
Non-residential	3	3	3	3	3	13
Gyumri						
Residential	2	2	2	2	2	8
Non-residential	2	2	2	2	2	11
Total Domestic						*78*
Total commercial						*107*
Total Armenia						**185**

Table 8 presents the annual installed building-PV capacities over the 5 years period considered for the two scenarios, for a total of:

- 92MW of installed building-PV under Medium Scenario (50% of the maximum potential);
- 185MW of installed building-PV under High Scenario (100% of maximum potential).

Table 8: High and Medium Scenarios for PV deployment in Armenia, residential and non-residential market segment, MW (2018-2022)

Total annual building-PV install Armenia (MW)	2018	2019	2020	2021	2022	Total over 5 years
Residential						
High	16	16	16	16	16	78
Medium	8	8	8	8	8	39
Non-residential						
High	21	21	21	21	21	107
Medium	11	11	11	11	11	53
Total						
High	37	37	37	37	37	185
Medium	18	18	18	18	18	92

Table 9 below summarises assumptions behind High and Medium Scenarios for Armenia.

Medium Scenario deployment levels are assumed to be achieved either:

- By adding to the currently available net metering scheme (which do not make building-PV investment profitable enough to incentivise investment in both market segments – see also discussion in Section 4.2) a capital grant support scheme in order to achieve an internal rate of return (IRR) of building-PV investments at least equal to the estimated WAAC (i.e. 13% for residential and 15% for non-residential market segments), or

- By implementing a FiT scheme for tariff levels which would make the investment profitable enough (resulting in the same IRR level as above), which would also provide a stable financial framework and increased levels of confidence among investors.

Policy assumptions for the High Scenario are similar to Medium Scenario, but for higher assumed IRR, i.e. 18% for residential and 20% for non-residential market segments, as we implicitly assume that higher investment profitability would incentivise higher deployment levels.

Table 9: Summary of Scenarios assumptions - Armenia

Scenario	Deployment (as % of Total building-PV potential)	Residential building-PV installation, MW	Non-residential building-PV installation, MW	TOTAL building-PV installation, MW	Policy support assumptions
High	100%	78	107	185	Net metering + Capital Grant (for IRR 13% for residential and 15% for non-residential)
					FiT (€/kWh) (for IRR 13% for residential and 15% for non-residential)
Medium	50%	39	53	92	Net metering + Capital Grant (for IRR 18% for residential and 20% for non-residential)
					FiT (€/kWh) (for IRR 18% for residential and 20% for non-residential)

3.2.2 Ukraine

Table 10 and Table 11 below present staged building-PV deployment in the two stages (i.e. up to 2024 and up to 2030) and the annual building-PV installation target for each city and market segment over the 2018-2022 period (which constitutes the maximum deployment potential over the timeframe considered, i.e. the High Scenario deployment level), respectively.

Table 10: Ukraine – staged deployment of maximum building-PV potential by 2030, MW

	2018-2024	2025-2030
Kyiv		

Residential	239	558
Non-residential	146	342
Odessa		
Residential	122	286
Non-residential	97	226
Lviv		
Residential	36	84
Non-residential	43	99
Zaporizhia		
Residential	31	73
Non-residential	71	34
Total	***785***	***1701***

Note: 30% of total PV capacity 2018-2024; 70% of total PV capacity 2025-2030

Table 11: Ukraine – Annual building-PV installation target per city and market segment (equal to High Scenario), MW

	2018	2019	2020	2021	2022	Total over 5 years
Kyiv						
Residential	34	34	34	34	34	171
Non-residential	21	21	21	21	21	105
Odessa						
Residential	17	17	17	17	17	87
Non-residential	14	14	14	14	14	69
Lviv						
Residential	5	5	5	5	5	26
Non-residential	6	6	6	6	6	30
Zaporizhia						
Residential	4	4	4	4	4	22
Non-residential	10	10	10	10	10	51
Total residential						*306*
Total non-residential						*255*
Total Ukraine						**561**

Table 12 presents the annual installed building-PV capacities over the 5 years period considered for the two scenarios, for a total of:

- 281MW of installed building-PV under Medium Scenario (50% of the maximum potential);
- 561MW of installed building-PV under High Scenario (100% of maximum potential).

Table 12: High and Medium Scenarios for PV deployment in Ukraine, residential and non-residential market segment, MW (2018-2022)

Total annual building-PV install Ukraine (MW)	2018	2019	2020	2021	2022	Total over 5 years
Residential						
High	61	61	61	61	61	306
Medium	31	31	31	31	31	153
Non-residential						
High	51	51	51	51	51	255
Medium	25	25	25	25	25	127
Total						
High	112	112	112	112	112	561
Medium	56	56	56	56	56	281

Table 13 below summarises assumptions behind High and Medium Scenarios for Ukraine.

As discussed in "Review of Eastern Partner Countries experience with building-PVs", Ukraine has already in place both a net metering and a FiT scheme. Indeed, Ukraine PV sector is slightly more developed with respect with other EaP countries: as of January 2017, PV installations reached nearly 530MW. However, the rooftop segment still remain quite limited, i.e. about 16MW installed, accounting for only 3% of the total PV capacity in the country. End user analysis results presented in Section 4.2 have shown how, under current FiT levels building-PV investments are not profitable enough to incentivise deployment. Similarly, it has also shown how under current levels of end user retail tariffs net metering also does not make building-PV an economically attractive investment. Therefore, it has been assumed to assess implications of two alternative policy support options, under Medium Scenario deployment levels, either:

- The introduction of a capital grant support (in conjunction to the current net metering scheme and as an alternative to a FiT scheme) in order to achieve an internal rate of return (IRR) of building-PV investments at least equal to the estimated WAAC (i.e. 12%), or

- The implementation of a FiT scheme for tariff levels which would make the investment profitable enough (resulting in the same IRR level as above). As also discussed in Section 4.2 such tariffs levels are higher than those offered under currently implemented FiT scheme in Ukraine.

Policy assumptions for the High Scenario are similar to Medium Scenario, but for higher assumed IRR, i.e. 17%, as we implicitly assume that higher investment profitability would incentivise higher deployment levels.

Table 13: Summary of Scenarios assumptions - Ukraine

<table>
<tr><th>Scenario</th><th>Deployment (as % of Total building-PV potential)</th><th>Residential building-PV installation, MW</th><th>Non-residential building-PV installation, MW</th><th>TOTAL building-PV installation, MW</th><th>Policy support assumptions</th></tr>
<tr><td rowspan="2">High</td><td rowspan="2">100%</td><td rowspan="2">306</td><td rowspan="2">255</td><td rowspan="2">561</td><td>Net metering + Capital Grant (for IRR 17%)</td></tr>
<tr><td>FiT (€/kWh) (for IRR 17%)</td></tr>
<tr><td rowspan="2">Medium</td><td rowspan="2">50%</td><td rowspan="2">153</td><td rowspan="2">127</td><td rowspan="2">281</td><td>Net metering + Capital Grant (for IRR 12%)</td></tr>
<tr><td>FiT (€/kWh) (for IRR 12%)</td></tr>
</table>

3.2.3 Moldova

Table 14 and Table 15 below present staged building-PV deployment in the two stages (i.e. up to 2024 and up to 2030) and the annual building-PV installation target for each city and market segment over the 2018-2022 period (which constitutes the maximum deployment potential over the timeframe considered, i.e. the High Scenario deployment level), respectively.

Table 14: Moldova - staged deployment of maximum building-PV potential by 2030, MW

	2018-2024	2025-2030
Chisinau		
Residential	8.6	20.0
Non-residential	8.9	20.7
Balti		
Residential	1.1	2.5
Non-residential	1.0	2.4
Cahul		
Residential	0.3	0.6
Non-residential	0.3	0.7
Total	***20.1***	***46.8***

Note: 30% of total PV capacity 2018-2024; 70% of total PV capacity 2025-2030

Table 15: Moldova – Annual building-PV installation target, per city and market segment (equal to High Scenario), MW

	2018	2019	2020	2021	2022	Total over 5 years
Chisinau						
Residential	1.22	1.22	1.22	1.22	1.22	6.12
Non-residential	1.26	1.26	1.26	1.26	1.26	6.32
Balti						
Residential	0.15	0.15	0.15	0.15	0.15	0.75
Non-residential	0.15	0.15	0.15	0.15	0.15	0.73

Cahul						
Residential	0.04	0.04	0.04	0.04	0.04	0.19
Non-residential	0.04	0.04	0.04	0.04	0.04	0.21
Total Domestic						*7.06*
Total commercial						*7.26*
Total						**14.33**

Table 16 presents the annual installed building-PV capacities over the 5 years period considered for the two scenarios, for a total of:

- 281MW of installed building-PV under Medium Scenario (50% of the maximum potential);

- 561MW of installed building-PV under High Scenario (100% of maximum potential).

Table 16: High and Medium Scenarios for PV deployment in Moldova, residential and non-residential market segment, MW (2018-2022)

Total annual building-PV install Moldova (MW)	2018	2019	2020	2021	2022	Total over 5 years
Residential						
High	1.4	1.4	1.4	1.4	1.4	7.1
Medium	0.7	0.7	0.7	0.7	0.7	3.5
Non-residential						
High	1.5	1.5	1.5	1.5	1.5	7.3
Medium	0.7	0.7	0.7	0.7	0.7	3.6
Total						
High	2.9	2.9	2.9	2.9	2.9	14.3
Medium	1.4	1.4	1.4	1.4	1.4	7.2

Table 17 below summarises assumptions behind High and Medium Scenarios for Moldova.

Medium Scenario deployment levels are assumed to be achieved either:

- By adding to the currently available net metering scheme (which do not make building-PV investment profitable enough to incentivise investment in both market segments – see also discussion in Section 3) a capital grant support scheme in order to achieve an internal rate of return (IRR) of building-PV investments at least equal to the estimated WAAC (i.e. 10%), or

- By implementing a FiT scheme for tariff levels which would make the investment profitable enough (resulting in the same IRR level as above), which would also provide a stable financial framework and increased levels of confidence among investors.

Policy assumptions for the High Scenario are similar to Medium Scenario, but for higher assumed IRR, i.e. 15%, as we implicitly assume that higher investment profitability would incentivise higher deployment levels.

Table 17: Summary of Scenarios assumptions - Moldova

Scenario	Deployment (as % of Total building-PV potential)	Residential building-PV installation, MW	Non-residential building-PV installation, MW	TOTAL building-PV installation, MW	Policy support assumptions
High	100%	7.1	7.3	14.3	Net metering + Capital Grant (for IRR 15%)
					FiT (€/kWh) (for IRR 15%)
Medium	50%	3.5	3.6	7.2	Net metering + Capital Grant (for IRR 10%)
					FiT (€/kWh) (for IRR 10%)

3.2.4 Belarus

Table 18 and Table 19 below present potential staged building-PV deployment in the two stages (i.e. up to 2024 and up to 2030) and what could potentially be the annual building-PV installation potential for each city and market segment over the 2018-2022 period, respectively.

Table 18: Belarus - staged deployment of maximum building-PV potential by 2030, MW

	2018-2024	2025-2030
Minsk		
Residential	122	284
Non-residential	102	239
Mogilev		
Residential	32	75
Non-residential	22	51
Vitebsk		
Residential	38	90
Non-residential	24	56
Total	***341***	***795***

Note: 30% of total PV capacity 2018-2024; 70% of total PV capacity 2025-2030

Table 19: Belarus – Annual building-PV installation potential, per city and market segment, MW

	2018	2019	2020	2021	2022	Total over 5 years
Minsk						
Residential	17	17	17	17	17	87
Non-residential	15	15	15	15	15	73
Mogilev						
Residential	5	5	5	5	5	23
Non-residential	3	3	3	3	3	15
Vitebsk						
Residential	5	5	5	5	5	27

	2018	2019	2020	2021	2022	Total over 5 years
Non-residential	3	3	3	3	3	17
Total residential						*138*
Total non-residential						*106*
Total						**243**

However, despite the potential for building-PV in each city and the fact that there is currently a rather favourable FiT support in the country, the market is very limited due to the conditioning of FiT on centrally defined capacity quotas and prohibition of natural persons to own a building PV system (see Component 2: “Review of EaP countries experience with building-PVs” report of this study). We have therefore assumed and analysed the implementation of a FiT based pilot programme with the target of installing 5MW a year for a total of 25MW over the 5 years period (i.e. 2018-2022) which represent the full continuation of the current policy which allows for FiT only for intra-quota installations. Moreover, accounting for the fact the current PV and electricity markets regulations do not allow individuals to invest and install PV systems, we have focused the analysis on non-residential market segment only (for different sizes of non-residential PV systems). Table 20 presents the annual installed building-PV capacities over the 5 years period considered for different PV system sizes. FiT levels are estimated in order to achieve an internal rate of return (IRR) of building-PV investments at least equal to the estimated WAAC of 10% (see Section 4 below).

Table 20: Building-PV deployment in Belarus, under 25MW Pilot Programme, MW (2018-2022)

	2018	2019	2020	2021	2022	Total over 5 years
Minsk						
Non-residential 5kW	0.6	0.6	0.6	0.6	0.6	2.8
Non-residential 25kW	0.6	0.6	0.6	0.6	0.6	2.8
Non-residential 100kw	0.6	0.6	0.6	0.6	0.6	2.8
Mogilev						
Non-residential 5kW	0.6	0.6	0.6	0.6	0.6	2.8
Non-residential 25kW	0.6	0.6	0.6	0.6	0.6	2.8
Non-residential 100kw	0.6	0.6	0.6	0.6	0.6	2.8
Vitebsk						
Non-residential 5kW	0.6	0.6	0.6	0.6	0.6	2.8
Non-residential 25kW	0.6	0.6	0.6	0.6	0.6	2.8
Non-residential 100kw	0.6	0.6	0.6	0.6	0.6	2.8
Non-residential 5kW						*8.3*
Non-residential 25kW						*8.3*
Non-residential 100kw						*8.3*
Total	***5***	***5***	***5***	***5***	***5***	***25***

Table 21: Summary of Scenarios assumptions - Belarus

Scenario	Building-PV deployment target, MW	Policy support assumptions
25 MW Pilot Programme	25	FiT (€/kWh) (for IRR 10%)

3.2.5 Azerbaijan

Table 22 and Table 23 below present potential staged building-PV deployment in the two stages (i.e. up to 2024 and up to 2030) and what could potentially be the annual building-PV installation potential for each city and market segment over the 2018-2022 period, respectively.

Table 22: Azerbaijan - staged deployment of maximum building-PV potential by 2030, MW

	2018-2024	2025-2030
Baku		
Residential	141	328
Non-residential	213	496
Sumgait		
Residential	16	38
Non-residential	22	51
Ganja		
Residential	14	33
Non-residential	18	43
Total	***424***	***988***

Note: 30% of total PV capacity 2018-2024; 70% of total PV capacity 2025-2030

Table 23: Azerbaijan – Annual building-PV installation potential, per city and market segment, MW

	2018	2019	2020	2021	2022	Total over 5 years
Baku						
Residential	20.1	20.1	20.1	20.1	20.1	100.55
Non-residential	30.4	30.4	30.4	30.4	30.4	151.84
Sumgait						
Residential	2.32	2.32	2.32	2.32	2.32	11.58
Non-residential	3.11	3.11	3.11	3.11	3.11	15.54
Ganja						
Residential	1.99	1.99	1.99	1.99	1.99	9.96
Non-residential	2.62	2.62	2.62	2.62	2.62	13.11
Total residential						*122.1*
Total non-residential						*180.5*
Total Azerbaijan						**302.6**

In Azerbaijan despite the fact that a firm PV deployment policy target of 50 MW which includes both distributed and large solar PV plants by 2020 has been fixed, the market is not well supported by an adequate support scheme and a complete regulatory framework for connection and access to the grid. A FiT scheme is theoretically in place, but no specific tariff level has been assigned to PV systems. We have therefore assumed and analysed the implementation of a FiT based 1000 roofs PV support programme with the target of installing 5 MW building-PV over the 5 years period (i.e. 2018-2022). Table 24 below presents the annual installed building-PV capacities over the 5 years period considered. FiT levels are estimated in order to achieve an internal rate of return (IRR) of building-PV investments at least equal to the estimated WAAC of 10% (see Section 4 below).

Table 24: Building-PV deployment in Azerbaijan, under 1000 rooftop Programme, MW (2018-2022)

	2018	2019	2020	2021	2022	Total over 5 years
Baku						
Residential	0.2	0.2	0.2	0.2	0.2	0.83
Non-residential	0.2	0.2	0.2	0.2	0.2	0.83
Sumgait						
Residential	0.17	0.17	0.17	0.17	0.17	0.83
Non-residential	0.17	0.17	0.17	0.17	0.17	0.83
Ganja						
Residential	0.17	0.17	0.17	0.17	0.17	0.83
Non-residential	0.17	0.17	0.17	0.17	0.17	0.83
Total Domestic						*2.5*
Total commercial						*2.5*
Total						**5.0**

Table 25: Summary of Scenarios assumptions - Azerbaijan

Scenario	Building-PV deployment target, MW	Policy support assumptions
1000 Rooftop Programme	5	FiT (€/kWh) (for IRR 10%)

4 End-user analysis

The end user analysis comprises an investment appraisal of building-PV systems for the two market segments assumed: residential and non-residential. A typical financial cash flow analysis of each investment type was conducted, in order to identify the Internal Rate of Return (IRR) of the specific investment. The aim is to understand the economics of current building-PV policy framework and to estimate the level of policy support, in terms of FiT or capital grant levels, necessary to achieve adequate investment returns, which may properly incentivise the deployment of building-PV both in the residential and non-residential market segments in each country.

The analysis has been conducted for the five years period assumed, i.e. 2018-2022, so as to provide the necessary inputs in terms of the level of policy support to the cost benefits analysis of the policy measures implemented under the different building-PV deployment scenarios as developed for each country in Section 3.2 above. Investment appraisal has been done for both residential and the non-residential market segments and for the deployment and policy scenarios described in Section 3.2.

4.1 Data and assumptions

A financial model was developed for each country and market segment (residential and non-residential) in order to enable the cash-flow analysis for the whole lifetime (20 years) of building-PV systems. System performance characteristics were taken from the analysis conducted in Component 3: "Quantification of the potential of building-PVs in Georgia and the rest of the Eastern Partner countries" report of this study and the average production of rooftop PV systems in the cities that were analysed was used for each country. Economic variables such as investment cost and O&M costs as well as other financial and macroeconomic assumptions were used based on literature review, discussions with local experts and rational thinking. Wholesale and end user electricity prices were taken from Component 2: "Review of Eastern Partner Countries experience with building-PVs" report of this study and, when possible, better refined thanks to information provided by national experts. It should be noted, that the results of the analysis are sensitive to the underlying assumptions of the data used. For example, in absence of robust enough projections and references, the end user electricity tariff has been assumed to increase over time according to the annual inflation which is not exactly the case. Hence, since projections over a long period (25 years) were necessary, the resulting IRR levels inevitably include a high degree of uncertainty, given the variance that can occur in capital cost and inflation rates over this long period. Data used for the analysis and relative sources are summarised in Table 26 to Table 30.

Table 26: Data used for the financial analysis model for Armenia

Key Input data		Net metering		Fit PPA		
Description	Unit	Residential	Non-Residential	Residential	Non-Residential	Comments
Technical Characteristics						
Installed capacity	kW	1.5	28.3	3.0	50	For NM capacity was calculated based on annual electricity consumption using a factor of 1.3 to account for non-optimum conditions/sizing. For FiT PPA indicative reasonable figures were used.
Annual Yield (1st Year)	kWh/kW	1,378	1,378	1,378	1,378	Based on Comp3 report average figure for the three cities incl. a 10% reduction to attribute for various inefficiencies.
Average annual panel output reduction	% first 10 years	0.50%	0.50%	0.50%	0.50%	
	% 10-20 years	1.00%	1.00%	1.00%	1.00%	
Self-consumption share or NM share	%	40%	40%			Estimate value from http://en.sma-sunny.com/en/basic-information-about-designing-systems-for-self-consumption/
Electricity Consumption Elements						
Electricity consumption	kWh/y	1550	30000	1550	30000	For residential according to WB study. For non-residential indicative.
Average annual electricity consumption increase	%	1.5%	1.5%	1.5%	1.5%	Assumptions
Electricity Tariff	AMD/kWh	46.20	46.20	46.20	46.20	Based on Comp2 report
	EURO/kWh	0.087	0.087	0.087	0.087	
Average annual electricity tariff increase	%	2.9%	2.9%	2.9%	2.9%	Equal to average inflation
Electricity Costs (1st year)	AMD/yr	71610	1386000	71610	1386000	
	EUR/y	134	2600	134	2600	
NM excess energy remuneration	EURO/kWh	0.040	0.040			Half of solar FiT (9c$/kWh)

Key Input data		Net metering		Fit PPA		
Description	**Unit**	**Residential**	**Non-Residential**	**Residential**	**Non-Residential**	**Comments**
Annual total electricity consumption (2016)	MWh	5,460,192				Source: IEA (http://www.iea.org/countries/non-membercountries/armenia/)
Cost Elements						
Specific Investment Cost (€/kWp)	€/kWp	1400	1200	1400	1200	Based on data for Georgia
Total Investment Cost	€	2,100	33,960	4,200	60,000	
Annual investment cost reduction	%	3%	3%	3%	3%	[http://www.nrel.gov/docs/fy15osti/64898.pdf : Analysts project that from 2014-2020, system prices will fall 16%-33% for residential systems and 26%-36% for utility-scale systems, or between 3%-12% per year](http://www.nrel.gov/docs/fy15osti/64898.pdf)
Insurance	%	0.005	0.005	0.005	0.005	From HELAPCO O&M costs for small rooftop systems 1.5% of investment. For non-residential systems max rate from IRENA report. http://www.irena.org/DocumentDownloads/Publications/IRENA_Cost-competitive_power_potential_SEE_2017.pdf
	€/kW/yr	7	6	7	6	
Annual O&M (€/kWp)	€/kWp	15	15	15	15	
	€/yr	23	440	45	750	
Investment Characteristics						
Equity share	%	30%	30%	30%	30%	Based on RoA's, SREP[1] report, Apr. 2014
Debt share	%	70%	70%	70%	70%	Based on RoA's, SREP report, Apr. 2014
Loan term	Years	10	10	10	10	Assumption
Loan interest	%	13.0%	10.7%	13.0%	10.7%	Based on RoA's, SREP report, Apr. 2014, +2% units for residential
Depreciation	years	0	5	0	5	For residential no depreciation is considered. Based on info from Invest in Armenia (*www.investinarmenia.am/en/)*
Project Lifetime	years	20	20	20	20	

[1] Republic of Armenia, Scaling up Renewable Energy Program, Investment Plan for Armenia, April 2014.

Key Input data		Net metering		Fit PPA		
Description	**Unit**	**Residential**	**Non-Residential**	**Residential**	**Non-Residential**	**Comments**
Equity Expected RoR	%	18.0%	18.0%	18.0%	18.0%	Based on RoA's, SREP report, Apr. 2014
Tax Rate	%	0.0%	0.0%	0.0%	20.0%	For NM and residential FiT no depreciation is considered. Corporate tax based on info from Invest in Armenia http://www.investinarmenia.am/en/corporate-taxation
Inflation (average)	%	2.9%	2.9%	2.9%	2.9%	Assumptions based on information from https://tradingeconomics.com/armenia/inflation-cpi/forecast
Benefits						
Electricity emission factor	tonnes CO_2/MWh	0.437				EBRD, 2009
Price of Carbon (2017)	€/t CO_2	6.68				http://markets.businessinsider.com/commodities/co2-emissionsrechte
		min	***max***	***average***		
Manufacturing and installation (jobs-year/MW)	jobs-year/MW	7.1	43	25.1		IRENA (2014), "The Socio-economic Benefits of Solar and Wind Energy". Available at: http://www.irena.org/DocumentDownloads/Publications/Socioeconomic_benefits_solar_wind.pdf
Operation and maintenance (jobs-year/MW)	jobs-year/MW	0.1	0.7	0.4		IRENA (2014), "The Socio-economic Benefits of Solar and Wind Energy". Available at: http://www.irena.org/DocumentDownloads/Publications/Socioeconomic_benefits_solar_wind.pdf

Table 27: Data used for the financial analysis model for Azerbaijan

Key Input data- Description	Unit	Fit PPA Residential	Fit PPA Non-Residential	Comments
Technical Characteristics				
Installed capacity	kW	5,0	5,0	Assumption
Annual Yield (1st Year)	kWh/kW	1.197	1.197	Based on Comp3 report for the two cities analysed incl. a 10% reduction to attribute for various inefficiencies.
Average annual panel output reduction	first 10 years	0,50%	0,50%	
	10-20 years	1,00%	1,00%	
Annual total electricity consumption (2016)	MWh	17,418,014		Source: IEA (http://www.iea.org/countries/non-membercountries/azerbaijan/)
Cost Elements				
Specific Investment Cost (€/kWp)	€/kWp	1400	1300	Based on Georgian figures
Investment Cost	€	4.200	13.000	
Annual investment cost reduction	%	3%	3%	http://www.nrel.gov/docs/fy15osti/64898.pdf : Analysts project that from 2014-2020, system prices will fall 16%-33% for residential systems and 26%-36% for utility-scale systems, or between 3%-12% per year
Insurance	%	0,005	0,005	From HELAPCO O&M costs for small rooftop systems 1.5% of investment. For non-residential systems max rate from IRENA report. http://www.irena.org/DocumentDownloads/Publications/IRENA_Cost-competitive_power_potential_SEE_2017.pdf
	€/kW/yr	7	7	
Annual O&M (€/kWp)	€/kWp	15	15	
	€/yr	45	150	
Investment Characteristics				
Equity share	%	30%	30%	Assumptions
Debt share	%	70%	70%	Assumptions
Loan term	Years	10	10	Assumptions
Loan interest	%	10%	8%	As in Moldova (assuming loans in foreign currency)
Depreciation	years	0	7	Assumption
Project Lifetime	years	20	20	
Equity RoR	%	10.0%	10.0%	
Tax Rate	%	0,0%	20%	No corp. tax for residential For non-residential figure from: https://www.pwc.com/az/en/publications/assets/dbg-az-2017.pdf

		Fit PPA		
Key Input data- Description	**Unit**	**Residential**	**Non-Residential**	**Comments**
Inflation (2017)	%	13,9%	13,9%	Times series instead of average figure was used based on short term forecast from https://tradingeconomics.com/azerbaijan/inflation-cpi/forecast (2017 estimate) and long term assumption for 4.3%.

Benefits

Electricity emission factor	tonnes CO_2/MWh	0.521			EBRD, 2009
Price of Carbon (2017)	€/t CO_2	6.68			http://markets.businessinsider.com/commodities/co2-emissionsrechte
		min	***max***	***average***	
Manufacturing and installation (jobs-year/MW)	jobs-year/MW	7.1	43	25.1	IRENA (2014), "The Socio-economic Benefits of Solar and Wind Energy". Available at: http://www.irena.org/DocumentDownloads/Publications/Socioeconomic_benefits_solar_wind.pdf
Operation and maintenance (jobs-year/MW)	jobs-year/MW	0.1	0.7	0.4	IRENA (2014), "The Socio-economic Benefits of Solar and Wind Energy". Available at: http://www.irena.org/DocumentDownloads/Publications/Socioeconomic_benefits_solar_wind.pdf

Table 28: Data used for the financial analysis model for Belarus

Key Input data - Description	Unit	Fit PPA				Comments
		Residential	Non-Residential			
			5kW	25kW	100kW	
Technical Characteristics						
Installed capacity	kW	3,0	5	25	100	Assumption
Annual Yield (1st Year)	kWh/kW	953	953	953	953	Based on Comp3 report for the two cities analysed incl. a 10% reduction to attribute for various inefficiencies.
Average annual panel output reduction	first 10 years	0,50%	0,50%	0,50%	0,50%	
	10-20 years	1,00%	1,00%	1,00%	1,00%	
Annual total electricity consumption (2016)	MWh	29,727,320				Source: IEA (http://www.iea.org/countries/non-membercountries/belarus/)
Cost Elements						
Specific Investment Cost (€/kWp)	€/kWp	1300	1300	1250	1200	Based on Moldovan figures
Investment Cost	€	3,900	6,500	31,250	120,000	
Annual investment cost reduction	%	3%	3%	3%	3%	http://www.nrel.gov/docs/fy15osti/64898.pdf : Analysts project that from 2014-2020, system prices will fall 16%-33% for residential systems and 26%-36% for utility-scale systems, or between 3%-12% per year
Insurance	%	0.005	0.005	0.005	0.005	From HELAPCO O&M costs for small rooftop systems 1.5% of investment. For non-residential systems max rate from IRENA report. http://www.irena.org/DocumentDownloads/Publications/IRENA_Cost-competitive_power_potential_SEE_2017.pdf
	€/kW/yr	7	7	6	6	
Annual O&M (€/kWp)	€/kWp	15	15	15	15	
	€/yr	45	75	375	1,500	
Investment Characteristics						
Equity share	%	30%	30%	30%	30%	Assumption
Debt share	%	70%	70%	70%	70%	Assumption
Loan term	Years	10	10	10	10	Assumption
Loan interest	%	10.0%	8.0%	8.0%	8.0%	As in Moldova (assuming loans in foreign currency)
Depreciation	years	0	7	7	7	Assumption
Project Lifetime	years	20	20	20	20	

Key Input data - Description	Unit	Fit PPA				Comments
		Residential	Non-Residential			
			5kW	25kW	100kW	
Equity RoR	%	10.0%	10.0%	10.0%	10.0%	As in Moldova
WACC	%	10.0%	8.6%	8.6%	8.6%	
Tax Rate	%	0	20.0%	20.0%	20.0%	https://www.pwc.com/az/en/publications/assets/dbg-az-2017.pdf
Inflation (2017)	%	6,0%	6,0%	6,0%	6,0%	Times series instead of average figure was used based on short term forecast from https://tradingeconomics.com/belarus/inflation-cpi/forecast and long term assumption for 3.8%.
Benefits						
Electricity emission factor	tonnes CO_2/MWh	0.468				EBRD, 2009
Price of Carbon (2017)	€/t CO_2	6.68				http://markets.businessinsider.com/commodities/co2-emissionsrechte
		min	***max***	***average***		
Manufacturing and installation (jobs-year/MW)	jobs-year/MW	7.1	43	25.1		IRENA (2014), “The Socio-economic Benefits of Solar and Wind Energy”. Available at: http://www.irena.org/DocumentDownloads/Publications/Socioeconomic_benefits_solar_wind.pdf
Operation and maintenance (jobs-year/MW)	jobs-year/MW	0.1	0.7	0.4		IRENA (2014), “The Socio-economic Benefits of Solar and Wind Energy”. Available at: http://www.irena.org/DocumentDownloads/Publications/Socioeconomic_benefits_solar_wind.pdf

Table 29: Data used for the financial analysis model for Moldova

Key Input data		Net metering		Fit PPA		
Description	Unit	Residential	Non-Residential	Residential	Non-Residential	Comments
Technical Characteristics						
Installed capacity	kW	1.9	35.9	3.0	50	For NM capacity was calculated based on annual electricity consumption using a factor of 1.3 to account for non-optimum conditions/sizing. For FiT PPA indicative reasonable figures were used.
Annual Yield (1st Year)	kWh/kW	1,086	1,086	1,086	1,086	Based on Comp3 report for Chisinau incl. a 10% reduction to attribute for various inefficiencies.
Average annual panel output reduction	% first 10 years	0.50%	0.50%	0.50%	0.50%	
	% 10-20 years	1.00%	1.00%	1.00%	1.00%	
Self-consumption share or NM share	%	40%	40%			Estimate value from http://en.sma-sunny.com/en/basic-information-about-designing-systems-for-self-consumption/
Electricity Consumption Elements						
Electricity consumption	kWh/y	1600	30000	1600	6000	For residential according to local expert. Indicative for non-residential
Average annual electricity consumption increase	%	1.5%	1.5%	1.5%	1.5%	Assumptions
Electricity Tariff	MDL/kWh	1.990	1.990	1.990	1.990	Based on Comp2 report (FENOSA MV and LV)
	EURO/kWh	0.094	0.094	0.094	0.094	
Average annual electricity tariff increase	%	5.3%	5.3%	5.3%	5.3%	Equal to average inflation
Electricity Costs (1st year)	MDL/yr	3184	59700	3184	11940	
	EUR/y	150	2818	150	564	
NM excess energy remuneration	EURO/kWh	0.052	0.052			Based on local expert.

Key Input data		Net metering		Fit PPA		
Description	Unit	Residential	Non-Residential	Residential	Non-Residential	Comments
Annual total electricity consumption (2016)	MWh	5,887,000				Source: IEA (http://www.iea.org/countries/non-membercountries/moldova/)
Cost Elements						
Specific Investment Cost (€/kWp)	€/kWp	1300	1200	1300	1200	Based on data from real systems costs
Total Investment Cost	€	2,470	43,080	3,900	60,000	
Annual investment cost reduction	%	3%	3%	3%	3%	http://www.nrel.gov/docs/fy15osti/64898.pdf : Analysts project that from 2014-2020, system prices will fall 16%-33% for residential systems and 26%-36% for utility-scale systems, or between 3%-12% per year
Insurance	%	0.005	0.005	0.005	0.005	From HELAPCO O&M costs for small rooftop systems 1.5% of investment. For non-residential systems max rate from IRENA report. http://www.irena.org/DocumentDownloads/Publications/IRENA_Cost-competitive_power_potential_SEE_2017.pdf
	€/kW/yr	7	6	7	6	
Annual O&M (€/kWp)	€/kWp	12	12	12	12	
	€/yr	23	431	36	600	
Investment Characteristics						
Equity share	%	30%	30%	30%	30%	Assumptions
Debt share	%	70%	70%	70%	70%	Assumptions
Loan term	Years	7	7	7	7	Assumptions
Loan interest	%	10.0%	8.0%	10.0%	8.0%	Based on local expert (assuming loan in foreign currency).
Depreciation	years	0	7	0	7	For residential no depreciation is considered. Assumption for non-residential
Project Lifetime	years	20	20	20	20	

Key Input data		Net metering		Fit PPA		
Description	**Unit**	**Residential**	**Non-Residential**	**Residential**	**Non-Residential**	**Comments**
Equity Expected RoR	%	10.0%	10.0%	10.0%	10.0%	Local Expert's report
Tax Rate	%	0.0%	0.0%	0.0%	20.0%	For NM and residential FiT no depreciation is considered. Corporate tax based on info from Invest in Armenia http://www.investinarmenia.am/en/corporate-taxation
Inflation (average)	%	5.3%	5.3%	5.3%	5.3%	Assumptions based on information from National Bank of Moldova on 20 yrs average assuming 5% future inflation according to Energy Efficiency Fund

Benefits					
Electricity emission factor	tonnes CO_2/MWh	0.521			EBRD, 2009
Price of Carbon (2017)	€/t CO_2	6.68			http://markets.businessinsider.com/commodities/co2-emissionsrechte
		min	***max***	***average***	
Manufacturing and installation (jobs-year/MW)	jobs-year/MW	7.1	43	25.1	IRENA (2014), "The Socio-economic Benefits of Solar and Wind Energy". Available at: http://www.irena.org/DocumentDownloads/Publications/Socioeconomic_benefits_solar_wind.pdf
Operation and maintenance (jobs-year/MW)	jobs-year/MW	0.1	0.7	0.4	IRENA (2014), "The Socio-economic Benefits of Solar and Wind Energy". Available at: http://www.irena.org/DocumentDownloads/Publications/Socioeconomic_benefits_solar_wind.pdf

Table 30: Data used for the financial analysis model for Ukraine

Key Input data		Net metering		Fit PPA		
Description	**Unit**	**Residential**	**Non-Residential**	**Residential**	**Non-Residential**	**Comments**
Technical Characteristics						
Installed capacity	kW	2.7	38.4	3.0	50	For NM capacity was calculated based on annual electricity consumption using a factor of 1.3 to account for non-optimum conditions/sizing. For FiT PPA indicative reasonable figures were used.
Annual Yield (1st Year)	kWh/kW	1,016	1,016	1,016	1,016	Based on Comp3 report for the three cities analysed incl. a 10% reduction to attribute for various inefficiencies.
Average annual panel output reduction	% first 10 years	0.50%	0.50%	0.50%	0.50%	
	% 10-20 years	1.00%	1.00%	1.00%	1.00%	
Self-consumption share or NM share	%	40%	40%			Estimate value from http://en.sma-sunny.com/en/basic-information-about-designing-systems-for-self-consumption/
Electricity Consumption Elements						
Electricity consumption	kWh/y	2080	30000	2080	30000	For residential based on Georgia figure and increased by 30% according to per capita residential consumption difference (IEA data). Indicative figure for non-residential
Average annual electricity consumption increase	%	1.5%	1.5%	1.5%	1.5%	Assumption
Electricity Tariff	UAH/kWh	1.875	2.099	1.875	2.099	Based on Comp2 report
	EURO/kWh	0.064	0.072	0.064	0.072	
Average annual electricity tariff increase	%	Equal to inflation				
Electricity Costs (1st year)	UAH/yr	3901	62980	3901	62980	
	EUR/y	134	2157	134	2157	

Key Input data		Net metering		Fit PPA		
Description	Unit	Residential	Non-Residential	Residential	Non-Residential	Comments
NM excess energy remuneration	EURO/kWh	0.026	0.026	0.026	0.026	Based on wholesale tariff for 2015 and production breakdown.
Annual total electricity consumption (2016)	MWh	120,773,835				Source: IEA (http://www.iea.org/countries/non-membercountries/ukraine/)
Cost Elements						
Specific Investment Cost (€/kWp)	€/kWp	1300	1200	1300	1200	Based on Moldovan figures.
Total Investment Cost	€	3,510	46,080	3,900	60,000	
Annual investment cost reduction	%	3%	3%	3%	3%	[http://www.nrel.gov/docs/fy15osti/64898.pdf : Analysts project that from 2014-2020, system prices will fall 16%-33% for residential systems and 26%-36% for utility-scale systems, or between 3%-12% per year](http://www.nrel.gov/docs/fy15osti/64898.pdf)
Insurance	%	0.005	0.005	0.005	0.005	From HELAPCO O&M costs for small rooftop systems 1.5% of investment. For non-residential systems max rate from IRENA report. http://www.irena.org/DocumentDownloads/Publications/IRENA_Cost-competitive_power_potential_SEE_2017.pdf
	€/kW/yr	7	6	7	6	
Annual O&M (€/kWp)	€/kWp	20	18	20	15	
	€/yr	53	691	59	750	
Investment Characteristics						
Equity share	%	30%	30%	30%	30%	Assumptions
Debt share	%	70%	70%	70%	70%	Assumptions
Loan term	Years	7	7	7	7	Assumptions
Loan interest	%	13.0%	13.0%	13.0%	13.0%	Based on NEURC suggestions (assuming loan in foreign currency).
Depreciation	years	0	7	0	7	For residential no depreciation is considered. Assumption for non-residential
Project Lifetime	years	20	20	20	20	

Key Input data		Net metering		Fit PPA		
Description	**Unit**	**Residential**	**Non-Residential**	**Residential**	**Non-Residential**	**Comments**
Equity Expected RoR	%	10%	10%	10%	10%	Based on NEURC suggestions
Tax Rate	%	0.0%	0.0%	0.0%	15.0%	For NM and residential FiT no depreciation is considered. Corporate tax based on info from Invest in Armenia http://www.investinarmenia.am/en/corporate-taxation
Inflation (2017)	%	11.6%	11.6%	11.6%	11.6%	Time series instead of average figure was used based on information from https://tradingeconomics.com/ukraine/inflation-cpi/forecast and assuming a 3.5% long term rate.

Benefits

Electricity emission factor	tonnes CO_2/MWh	0.807			EBRD, 2009
Price of Carbon (2017)	€/t CO_2	6.68			http://markets.businessinsider.com/commodities/co2-emissionsrechte
		min	***max***	***average***	
Manufacturing and installation (jobs-year/MW)	jobs-year/MW	7.1	43	25.1	IRENA (2014), "The Socio-economic Benefits of Solar and Wind Energy". Available at: http://www.irena.org/DocumentDownloads/Publications/Socioeconomic_benefits_solar_wind.pdf
Operation and maintenance (jobs-year/MW)	jobs-year/MW	0.1	0.7	0.4	IRENA (2014), "The Socio-economic Benefits of Solar and Wind Energy". Available at: http://www.irena.org/DocumentDownloads/Publications/Socioeconomic_benefits_solar_wind.pdf

4.2 Results and conclusions

As a starting point of the analysis the Levelised Cost of Energy (LCOE) for various investment cost and WACC levels was calculated for all countries.[2] In general the LCOE levels are much higher than current end user electricity tariffs, indicating that building-PV cannot compete with current electricity price levels in absence of a specific policy support scheme. Therefore, our analysis concludes that in most cases the NM or self-consumption schemes alone are not currently quite attractive.

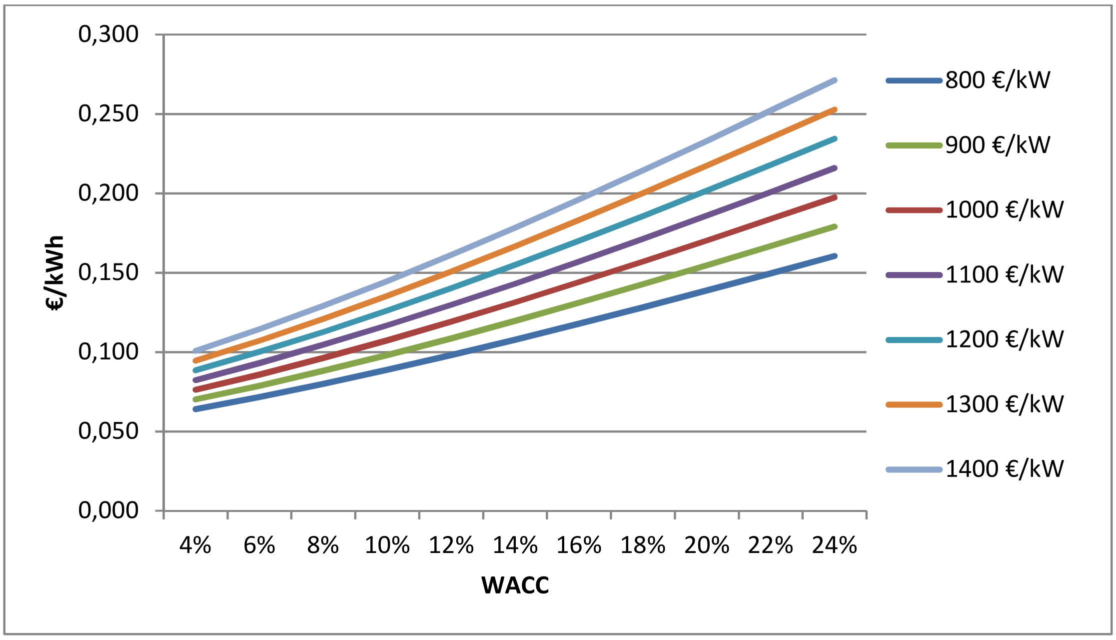

Figure 1: LCOE for various investment cost and WACC levels in Armenia

[2] The calculations of the LCOE were based on the simplified formula were only investment and O&M costs are used, not taking into account taxes.

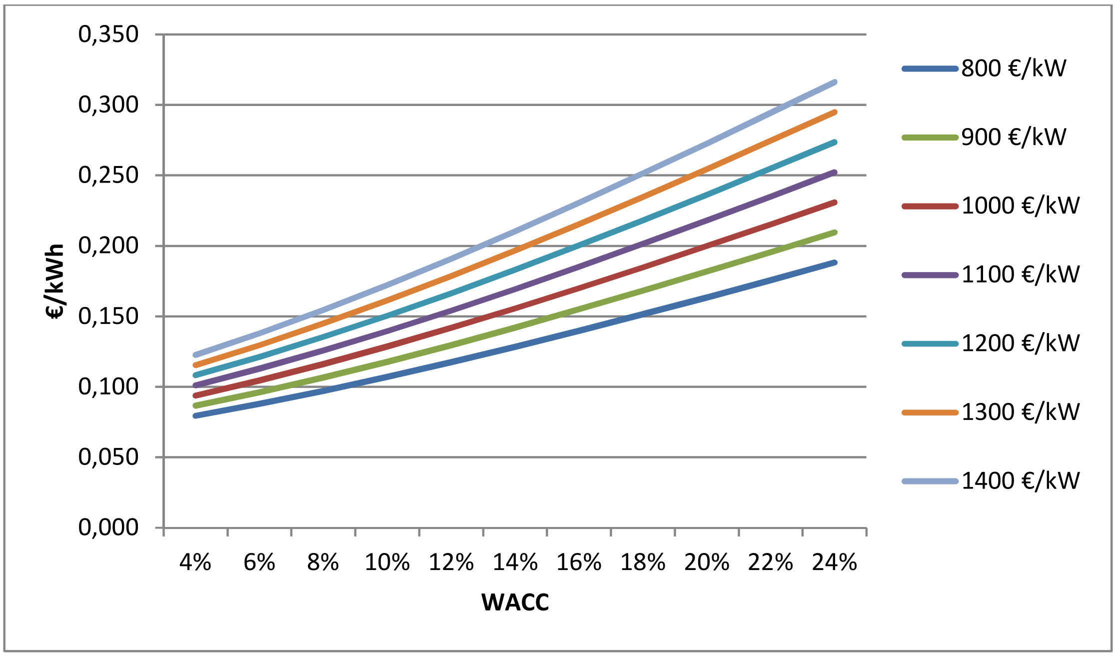

Figure 2: LCOE for various investment cost and WACC levels in Azerbaijan

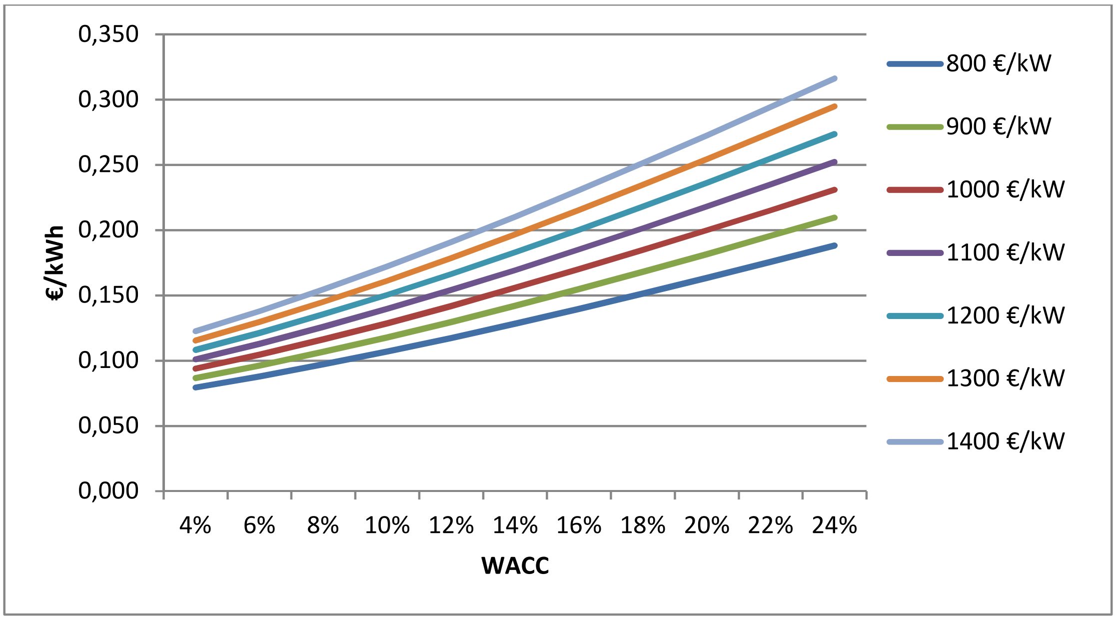

Figure 3: LCOE for various investment cost and WACC levels in Belarus.

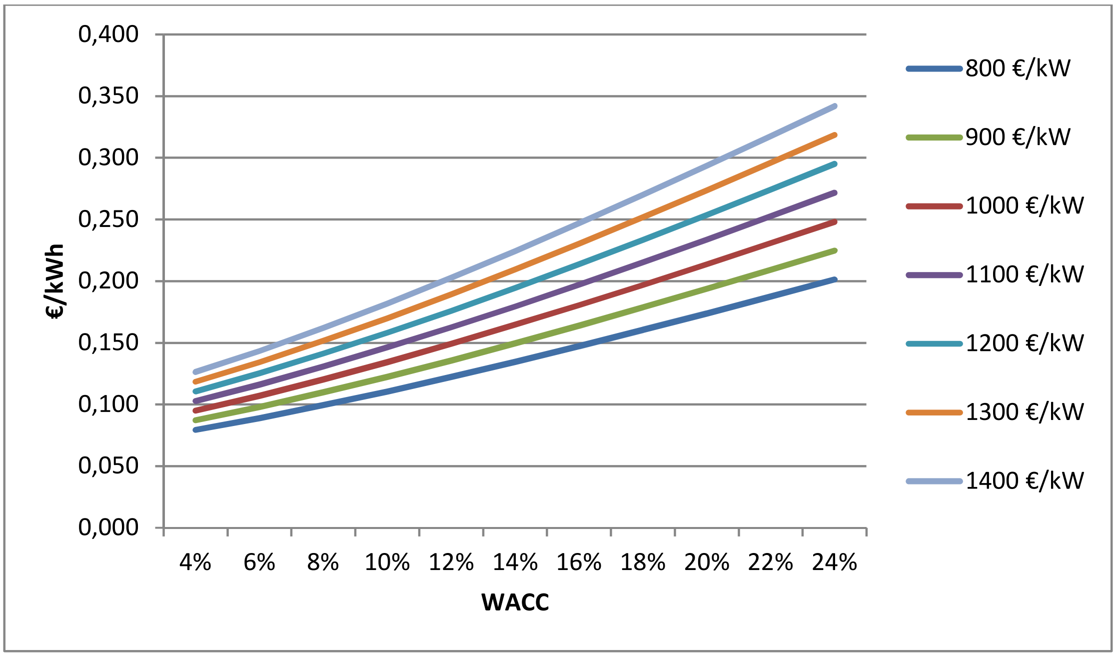

Figure 4: LCOE for various investment cost and WACC levels in Moldova

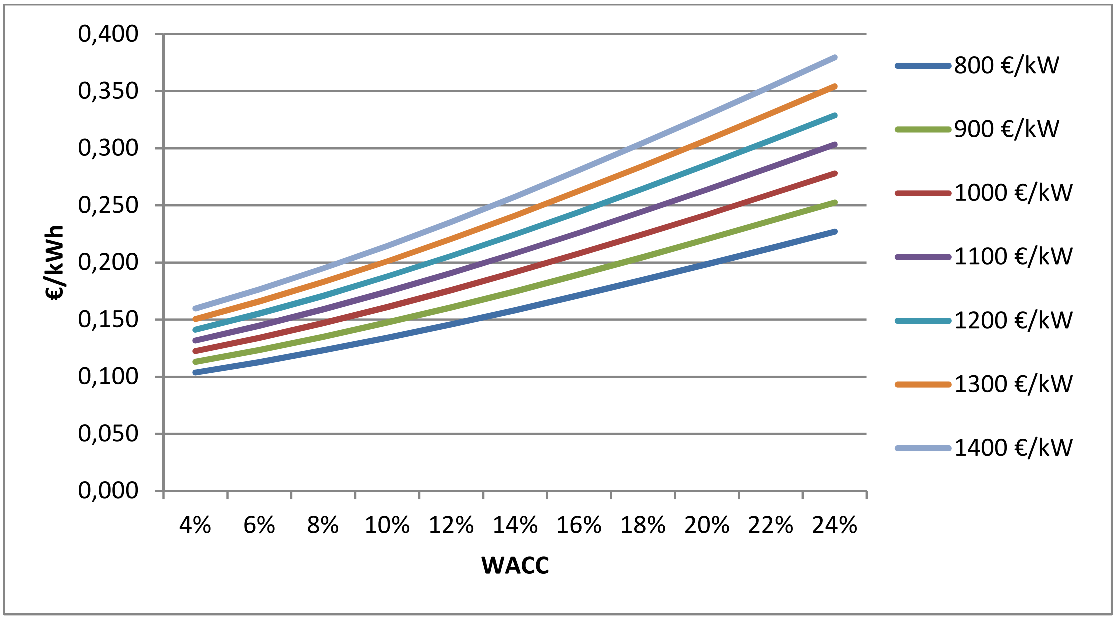

Figure 5: LCOE for various investment cost and WACC levels in Ukraine

Aiming to compare the attractiveness of building PV technology in each country, Table 31 below summarises the Levelised Cost of Energy (LCOE) taking as a basis of comparison a unit investment cost of €1000/kWp and a WACC of 12%):

Table 31: Comparison of LCOE in each country (for 1000€/kWp investment cost and 12%WACC)

Country	LCOE (€/MWh)
Armenia	119
Azerbaijan	142
Belarus	175
Moldova	152
Ukraine	176
Georgia	153

Table 32 to Table 36 therefore present results in terms of policy levels necessary to make building-PV investments profitable enough to incentivise investments in residential and non-residential market segments in each country and as assumed in scenario building in Section 3.2, more specifically:

- Annual capital grant, as a percentage of the initial building-PV investment cost (%);
- Annual generation tariff offered under the FiT scheme (€/kWh)

For all scenarios - apart from Azerbaijan as it is discussed below - the difference between policy support levels for residential and non-residential segment is due to the lower initial investment costs occurring in the non-residential segment, due to economies of scale and better financial conditions (lower reasonable IRR level). Moreover, the level of support, both the capital grant and the FiT, decreases over time, as a consequence of assumed reductions over time in building-PV investment cost.

For **Armenia** the NM scheme seems rather uneconomical and significant grant support would be necessary for both residential and non-residential systems in both scenarios. The FiT levels range start from 150€/MWh for non-residential to 178€/MWh for residential systems for the Low Scenario and from 168€/MWh and 200€/MWh respectively for the High deployment scenario.

Table 32: Results of end-user analysis for Armenia

Scenarios – market segments			YEAR 1	YEAR 2	YEAR 3	YEAR 4	YEAR 5
Medium	**Net Metering + grant (% of total cost)**	**Residential (IRR 15%)**	51.8%	48.1%	44.0%	39.6%	34.9%
		Non-residential (IRR 13%)	33.7%	28.6%	23.1%	17.1%	11.0%
	FiT (€/kWh)	**Residential (IRR 15%)**	0.178	0.174	0.169	0.164	0.160
		Non-residential (IRR 13%)	0.150	0.146	0.142	0.138	0.135
High	**Net Metering + grant (% of total cost)**	**Residential (IRR 20%)**	59.0%	56%	52%	48%	44%
		Non-residential (IRR 18%)	44.7%	40%	36%	31%	25%
	FiT (€/kWh)	**Residential (IRR 20%)**	0.200	0.195	0.189	0.184	0.179
		Non-residential (IRR 18%)	0.168	0.164	0.159	0.155	0.150

For **Azerbaijan** the analysis indicated the appropriate levels of FiT for a rooftop-PV program. Based on the underlying assumptions the differences between residential and non-residential systems are low, as only small scale systems were analysed for both cases, thus lacking the economies of scale factor. In this case FiT levels for non-residential seem slightly higher due to the inclusion of taxation, despite the relatively better financing conditions.

Table 33: Results of end-user analysis for Azerbaijan

1000 Rooftop Program - Market segments		YEAR 1	YEAR 2	YEAR 3	YEAR 4	YEAR 5
FiT (€/kWh)	Residential (IRR10%)	0.161	0.157	0.153	0.149	0.145
	Non-residential (IRR 10%)	0.163	0.159	0.155	0.151	0.147

For **Belarus** a FiT scheme was analysed for various system configurations. The FiT levels are summarised in the following table.

Table 34: Results of end-user analysis for Belarus

25 MW Pilot Program – Market segments		YEAR 1	YEAR 2	YEAR 3	YEAR 4	YEAR 5
FiT €/kWh)	Non-residential 5kW (IRR10%)	0.202	0.196	0.191	0.186	0.181
	Non-residential 25kW (IRR10%)	0.195	0.190	0.185	0.180	0.175
	Non-residential 100kW (IRR10%)	0.188	0.183	0.178	0.174	0.169

For **Moldova** the assumption regarding the evolution of electricity end user prices results in the NM scheme becoming relatively profitable for the non-residential case in three years' time and in four years for the residential case (average 20yr LV tariff of 0,182€/kWh). Therefore, we assumed that capital grant was not needed anymore for those years. However, if further deployment should be reached through an increased IRR of 15%, additional grants would be required. Concerning the FiT scheme, the analysis indicates relatively high FiT levels compared to other countries mainly due to lower annual yield of the PV systems.

Table 35: Results of end-user analysis for Moldova

Scenarios - Business cases			YEAR 1	YEAR 2	YEAR 3	YEAR 4	YEAR 5
Low (10% IRR)	Net Metering + grant (% of total cost)	Residential	25.4%	17.3%	8.7%	-	-
		Non-residential	15.0%	6.2%	-	-	-
	FiT (€/kWh)	Residential	0.204	0.198	0.193	0.188	0.183
		Non-residential	0.188	0.183	0.178	0.173	0.169
High		Residential	43%	36%	30%	22%	14%

Scenarios - Business cases			YEAR 1	YEAR 2	YEAR 3	YEAR 4	YEAR 5
(15% IRR)	Net Metering + grant (% of total cost)	Non-residential	35%	28%	20%	12%	3%
	FiT (€/kWh)	Residential	0.236	0.230	0.223	0.217	0.211
		Non-residential	0.216	0.210	0.204	0.199	0.193

Finally, in **Ukraine** the analysis indicates that at current and future end user tariffs the NM scheme requires substantial grants in order to become economically meaningful. Moreover, the current FiT scheme was initially analysed resulting in negative IRR levels for the underlying investment assumptions of small scale systems. Hence a new scheme without the current provisions for FiT payment until 2031 (and wholesale tariffs thereafter) was analysed resulting in higher than current (162€/MWh) FiT levels as depicted in the following table.

Table 36: Results of end-user analysis for Ukraine

Scenarios - Business cases			YEAR 1	YEAR 2	YEAR 3	YEAR 4	YEAR 5
Medium (12% IRR)	Net Metering + grant (% of total cost)	Residential	74.7%	70.6%	66.9%	63.2%	59.4%
		Non-residential	65.0%	60.0%	55.3%	51.1%	46.2%
	FiT (€/kWh)	Residential	0.228	0.220	0.214	0.208	0.203
		Non-residential	0.216	0.209	0.203	0.197	0.192
High (17% IRR)	Net Metering + grant (% of total cost)	Residential	79.2%	75.9%	72.6%	69.6%	66.5%
		Non-residential	71.2%	67.2%	63.2%	59.5%	55.5%
	FiT (€/kWh)	Residential	0.252	0.244	0.237	0.231	0.225
		Non-residential	0.238	0.230	0.223	0.217	0.211

5 Cost and benefit of policy support

In this section, we present the cost benefit analysis of the policy measures implemented under the different building-PV deployment scenarios developed in Section 3.2 for Armenia, Azerbaijan, Belarus, Moldova and Ukraine. The cost benefit analysis provides aggregated results at system's level, i.e. from the 'social planner' point view. In this section we first present the main assumptions and data and then follow on with the results of the cost benefit analysis.

5.1 Assumptions and data

To recap assumptions taken, we have developed for Armenia, Ukraine and Moldova target future building-PV penetration scenarios, assuming different levels of deployment over the 2018-2022 period of the total building-PV potential estimated for each city and in each country, in particular:

- a High Scenario which assumes that the total potential is actually achieved (to 100%);
- a Medium Scenario which assumes a 50% deployment.

For each of them we have assumed two alternative potential building-PV policy support measures:

- The addition to the currently available net metering scheme (which do not make building-PV investment profitable enough to incentivise investment in both market segments – see also discussion in Section 3) of a capital grant support scheme in order to achieve an internal rate of return (IRR) of building-PV investments at least equal to the estimated WAAC, or
- the implementation of a FiT scheme for tariff levels which would make the investment profitable enough (resulting in the same IRR level as above), which would also provide a stable financial framework and increased levels of confidence among investors.

The main difference between High and Medium Scenarios is the assumed IRR (5% higher under the High Scenarios), implying that higher investment profitability would incentivise higher deployment levels.

For Belarus and Azerbaijan instead, we have assumed the implementation of a specific FiT based policy support programme with the target of respectively 25MW and 5MW of building-PV installed over the 5 years period (i.e. 2018-2022).

For each country and scenario, we have calculated:

- the cost of policy measures assumed using figures of FiT and capital grants, estimated by the end-user analysis in Section 3.2.
- The potential economic impact of the implementation of the FiT scheme on electricity consumers.
- The quantifiable environmental and social benefits: the value of CO2 emissions reductions achieved and the number of jobs created by the implementation of building-PV capacity under different scenarios.

5.1.1 Cost of policy support

The cost of both policy measures is calculated using the figures of FiT and capital grants, estimated by the end-user analysis in Section 4.2 and presented in Table 32 to Table 36 above.

For the capital grant, the estimated annual percentage of the initial investment cost is applied to the investment cost associated to the annual building-PV installation, calculated for each city and market segment, under Low and High Scenarios deployment levels.

For the FiT scheme, we have initially calculated the annual energy yield (in kWh) according to the deployment levels (in MW) assumed under Medium and High Scenarios for each city and market segment over the 20 years lifetime, by using the first year's annual yield figure and the average annual panel output reduction, as presented in Table 26 to Table 30.

The aggregated cost of the FiT scheme, at system's level, accounts both for the overall cost of the incentive, and for the value created for the system due to the electricity generated by the building-PV deployment and fed into the specific country electricity grid. It is indeed calculated by:

1. multiplying the annual generation over the lifetime of 20 years (kWh) by the FiT level of the relative year of installation, for each city and each market segment;

2. and subtracting the value of the annual electricity generated, valued at the relative annual wholesale electricity price in 2018, and assuming an annual increase over the lifetime of the PV system (see Table 26 to Table 30 for specific data).

The economic analysis has been carried out, based on the assumption of a FiT scheme offering to building-PV owners a generation tariff for the total PV electricity generated and fed into the grid. This assumption implies that no self-consumption or net metering mechanism is taken into account for the design of the scheme. In other words, under such a FiT scheme, the building-PV systems would be connected to the main grid with the sole purpose to inject all the electricity generated to the system. The electricity consumed in the building where the PV has been installed, would be measured and billed via a different meter. For the purpose of this study, under this FiT scheme design assumptions, the PV generated electricity fed into the grid has been valued at the national average wholesale price.

It should be noted, however, that in several EU countries, the FiT scheme to support building-PV has been designed in order also to allow self-consumption and in some cases net metering. In this case, the FiT is designed as a tariff given to all kWh generated in the PV system, whereas the electricity is either consumed on site or sold to the market or included in a net metering mechanism or a combination of the above.

FiT mechanisms accounting for self-consumption may result to be less costly than FiT schemes based on generation tariff (as assumed in this study) as the final cost of the policy may be calculated as the difference between the total cost of the FiT (calculated as at point 1 above) and a value of the electricity generated at a price which is considerably higher than when valued at wholesale price. Indeed, whereas in the first case we calculate the cost of building-PV FiT support as the total of FiT cost minus the wholesale value of the electricity generated (as we do in this study), allowing self-consumption would imply that we should calculate it assuming a higher value for the electricity component as it would include not only the value of electricity fed into the grid (valued at wholesale price), but also the value of the electricity self-consumed and not fed into the grid (valued at the higher retail electricity prices). This in turn implies that the overall cost of the policy, which has been defined as the difference between the level of remuneration needed to support building PV and the value of electricity, would be lower.

This is to say, that the calculated FiT policy cost in this study (i.e. FIT scheme based on generation tariff) deliberately aims at the highest policy cost, whereas alternative designs of FiT combined with self-consumption scheme may result in a lower policy cost.

5.1.2 Impact on retail electricity consumers

The potential economic impact of the implementation of the FiT scheme on electricity consumers has been estimated by:

- Calculating the annual cost of the FiT scheme per kWh consumed, namely by dividing the annual Georgian electricity consumption by the total annual FiT scheme cost;
- Calculating the impact on household's annual bill, namely by multiplying the annual cost per kWh consumed by households' annual electricity consumption.

This estimation essentially implies that the overall system cost of the FiT scheme is charged and passed on to the consumer by means of a RES levy. It further implies, that the cost is equally distributed to all consumers while in reality a regulatory burden sharing method is almost always used, in order to allocate the costs to various consumer categories based on specific targets (e.g. protect industrial consumers, minimise welfare losses etc.). Due to data availability constraints, in particular in terms of annual electricity consumption for non-residential consumers, we have only estimated the economic impact on households' bills. Data used are presented in Table 26 to Table 30.

5.1.3 Environmental and social benefits

Analysis of environmental and social benefits has been focused on the quantification of benefits in terms of:

- Value of CO2 emissions reductions achieved by the implementation of building-PV capacity;
- Number of jobs created.

Contribution of building-PV deployed to CO_2 emission reductions has been calculated by applying the country specific electricity emission factor (tonnes CO_2/MWh) to the total electricity produced over the lifetime by the building-PV capacity deployed, under the three scenarios and over the programme's period considered (i.e. 2018-2022). The economic value of such CO_2 emissions reduction has been estimated multiplying them by the EU ETS price of carbon. The 2017 level of the EU price of carbon has been used as a base level and for the investment's period, despite the fact that fluctuations may well occur in the future, as it was beyond the project's goal to carry out an in-depth analysis of this parameter. Still, the calculations can be easily updated in a future follow-up to the project. Data used and their respective references are presented in Table 26 to Table 30.

Deployment of PV has the potential to generate income and create jobs, depending on the extent to which industry, along the different segments of the PV value chain, can employ people locally, leverage existing economic activities or create new ones. The analysis should in theory focus and be disaggregated on the basis of information and data on the core segments of the PV value chain: project planning, procurement, manufacturing, transport, installation and grid connection, operation and maintenance (O&M) and decommissioning[3]. However, the lack of available data on the regional PV supply chain, mainly due to the fact that the sector is still in its infancy, has severely hindered such a detailed approach of analysis. Therefore, we could only provide an indicative estimate of the impact expected in terms of direct job creation, by applying international estimates of jobs created per MW installed and combining it with the installed building-PV capacity under the three implementation scenarios. In particular, we have used the "employment factor" approach, which indicates the number of full-time equivalent (FTE) jobs created per physical unit of choice, in our case the installed PV peak capacity, but could also be the produced energy. It is used for different phases of the life cycle, those were, for the purpose of this analysis, divided in: manufacturing and installation, operation and maintenance. Employment factors for PV technologies vary in literature, mainly due to variations of labour productivity across countries. For example, employment factor for PV construction in OECD countries is lower than in India (i.e. respectively 11 and 39.6 jobs-year/MW[4]).

To account for this effect, we decided to use an average figure between minimum and maximum PV employment figures provided by IRENA[5]. Such figures have been multiplied by the annual building-PV installed capacity for each market segment and under the three scenarios assumed. A summary of data and their respective references are provided on Table 26 to Table 30.

For more details on methods used for cost of policy calculations please refer to Section 5 of Component 4: "Programme development for building-PVs based on a Cost-Benefit Analysis: Georgia" report of this study.

5.2 Results

5.2.1 Armenia

Table 37 presents summary of results of the cost and benefit analysis for Armenia. Of the total building-PV capacity potential of 861MW estimated in Component 3: "Quantification of the potential of building-PVs in Georgia and the rest of the Eastern Partner countries" report of this study, we estimate that about 92MW would be deployed under Medium Scenario and 185MW under High Scenario. This would imply, for the Medium Scenario, an annual building PV deployment of about 18MW/year for a policy cost of either:

- an average annual capital grant cost of € 7.2 million/year, for a total cost over the 2018-2022 period of about € 36.4 million, or
- a comparable average annual FiT scheme cost of € 7.6 million/year, but for a much higher total cost over the lifetime of the FiT scheme of € 191.5 million.

Under the High Scenario more building-PV is annually deployed, i.e. about 37MW/year, for higher average annual and total policy costs for both capital grant and FiT scheme. Thus, average annual costs of the two policy options considered are comparable, but the overall total policy cost over the lifetime of the programme is much higher in the case of FiT scheme. However, it is relevant to notice how evidence from other European countries which successfully developed domestic

[3] IRENA (2014), "The Socio-economic Benefits of Solar and Wind Energy". Available at: http://www.irena.org/DocumentDownloads/Publications/Socioeconomic_benefits_solar_wind.pdf
[4] IRENA (2014), as above
[5] IRENA (2014), as above

PV markets as presented in Component 1: “Review of EU experience with solar PV in buildings” report of this study, highlights high FiT scheme effectiveness in deploying distributed PV systems. This is mainly due to the implicit characteristics of the FiT schemes, which provide investors with a safe investment, offering a predictable and stable policy framework over the lifetime of the projects. Moreover, such characteristic allow FiT schemes to create more favourable conditions to mobilise private and institutional capital as well as to incentivise local bank to open building-PV specific credit lines.

The average estimated potential economic impact on households’ electricity consumers, as a result of the implementation of FiT scheme under the Medium and High Scenario, is also presented in Table 37. Average annual cost of the FiT per kWh consumed is very low, i.e. respectively €0.001 per MWh under Medium Scenario and €0.003 per MWh under High Scenario. On average, households’ electricity bills would increase respectively by €2.17 per year under Medium Scenario and by €5.33 under High Scenario.

Results in terms of CO_2 emissions’ reductions achieved and number of jobs created by the deployment of the building-PV capacity (MW) assumed under the two scenarios are presented in Table 37. CO_2 emissions saved range from about 1 million t/CO_2 under Medium Scenario to over 2 million t/CO_2 under High Scenario. This is equivalent to potential revenues, if traded at EU price of carbon, of over €6.9 million under Medium Scenario to over €13.9 million under High Scenario. Total direct jobs created over the lifetime of the programme range from 2,348 jobs under Medium Scenario to over 4,000 jobs created under High Scenario.

5.2.2 Ukraine

In Table 38 is presented the summary of the results for the cost and benefit analysis for Ukraine. Of the total building-PV capacity potential of 2,513MW estimated in Component 3: “Quantification of the potential of building-PVs in Georgia and the rest of the Eastern Partner countries” report of this study, we estimate that about 281MW would be deployed under Medium Scenario and 561MW under High Scenario. This would imply, for the Medium Scenario, an annual building PV deployment of about 56MW/year for a policy cost of either:

- an average annual capital grant cost of about € 41 million/year, for a total cost over the 2018-2022 period of about € 206 million, or
- a slightly lower average annual FiT scheme cost of € 35.7 million/year, but for a much higher total cost over the lifetime of the FiT scheme of € 894 million.

Under the High Scenario more building-PV is annually deployed, i.e. about 112MW/year, for higher average annual and total policy costs for both capital grant and FiT scheme. Thus, despite the average annual costs of FiT scheme is lower than annual capital grant cost, the overall total policy cost over the lifetime of the programme is much higher in the case of FiT scheme. However, it is relevant to notice how evidence from other European countries which successfully developed domestic PV markets as presented in Component 1: “Review of EU experience with solar PV in buildings” report of this study, highlights high FiT scheme effectiveness in deploying distributed PV systems.

The average estimated potential economic impact on households’ electricity consumers, as a result of the implementation of FiT scheme under the Medium and High Scenario, is also presented in Table 38. Average annual cost of the FiT per kWh consumed is almost negligible but multiplied by the average annual household consumption (in kWh) still lead to an impact on households' electricity bills, which would increase respectively by €0.61 per year under Medium Scenario and by €1.39 under High Scenario.

Results in terms of CO_2 emissions' reductions achieved and number of jobs created by the deployment of the building-PV capacity (MW) assumed under the two scenarios are presented in Table 38. CO_2 emissions saved range from over 4 million t/CO_2 under Medium Scenario to over 8 million t/CO_2 under High Scenario. This is equivalent to potential revenues, if traded at EU price of carbon, of over € 28 million under Medium Scenario to over € 57 million under High Scenario. Total direct jobs created over the lifetime of the programme range from over 7,000 jobs under Medium Scenario to over 14,000 jobs created under High Scenario.

5.2.3 Moldova

Table 39 presents summary of results of the cost and benefit analysis for Moldova. Of the total building-PV capacity potential of 67MW estimated in Component 3: "Quantification of the potential of building-PVs in Georgia and the rest of the Eastern Partner countries" report of this study, we estimate that about 7MW would deployed under Medium Scenario and 14MW under High Scenario. This would imply, for the Medium Scenario, an annual building PV deployment of about 1.4MW/year for a policy cost of either:

- an average annual capital grant cost of about € 130,000/year, for a total cost over the 2018-2022 period of about € 646,000, or
- a much higher average annual FiT scheme cost of about € 487,000/year, for a total cost over the lifetime of the FiT scheme of over € 12 million.

Under the High Scenario more building-PV is annually deployed, i.e. about 2.8MW/year, for higher average annual and total policy costs for both capital grant and FiT scheme. Both the average annual costs and the overall total policy cost over the lifetime of the programme is higher if a FiT scheme implemented than a capital grant support programme. However, it is relevant to notice how evidence from other European countries which successfully developed domestic PV markets as presented in Component 1: "Review of EU experience with solar PV in buildings" report of this study, highlights high FiT scheme effectiveness in deploying distributed PV systems.

The average estimated potential economic impact on households' electricity consumers, as a result of the implementation of FiT scheme under the Medium and High Scenario, is also presented in Table 39. Average annual cost of the FiT per kWh consumed is negligible; when multiplied by the average annual household consumption (in kWh) lead to a very limited impact on households' electricity bills, which would increase respectively by €0.13 per year under Medium Scenario and by €0.35 under High Scenario.

Results in terms of CO_2 emissions' reductions achieved and number of jobs created by the deployment of the building-PV capacity (MW) assumed under the two scenarios are presented in Table 39. CO_2 emissions saved range from over 76,000 million t/CO_2 under Medium Scenario to over 152,000 million t/CO_2 under High Scenario. This is equivalent to potential revenues, if traded at EU price of carbon, of over € 500,000 under Medium Scenario to over € 1 million under High Scenario. Total direct jobs created over the lifetime of the programme range from 152 jobs under Medium Scenario to 365 jobs created under High Scenario.

5.2.4 Belarus

Table 40 presents summary of results of the cost and benefit analysis of the implementation of the FiT scheme based 25MW programme in Belarus, over the 2018-2022 period. The estimated average annual FiT scheme cost of about € 1.7 million/year, for a total cost over the lifetime of the FiT scheme of over € 43 million. The average annual cost of the FiT per kWh consumed is very negligible; when multiplied by the average annual household consumption (in kWh) lead to a very limited impact on households' electricity bills, which would increase respectively by €0.10 per year.

The implementation of 25MW of building-PV would save about 210,000 CO_2 emissions, which is equivalent to potential revenues, if traded at EU price of carbon, of over € 1.4 million. Total direct jobs created over the lifetime of the programme are estimated to be about 630.

5.2.5 Azerbaijan

Table 41 presents summary of results of the cost and benefit analysis of the implementation of the FiT scheme based 1000 rooftop programme in Azerbaijan, which would allow installation of 5MW over 2018-2022 period. The estimated average annual FiT scheme cost of about € 430,000/year, for a total cost over the lifetime of the FiT scheme of over € 10 million. The average annual cost of the FiT per kWh consumed is very negligible; when multiplied by the average annual household consumption (in kWh) lead to a very limited impact on households' electricity bills, which would increase respectively by €0.06 per year.

The implementation of 5MW of building-PV would save over 58,000 CO_2 emissions, which is equivalent to potential revenues, if traded at EU price of carbon, of about € 340,000. Total direct jobs created over the lifetime of the programme are estimated to be about 127.

Table 37: Summary cost benefit analysis results - Armenia

Summary of Results - Armenia				
PV capacity potential, MW (Component 3)	861			
	Medium Scenario		**High Scenario**	
Estimated total installed capacity over 2018-2022 (MW)	**92**		**185**	
Total electricity produced over lifetime (kWh)	2,394,075,084		4,786,936,195	
Policy implemented	**Capital Grant €/MW**	**FiT €/kWh**	**Capital Grant €/MW**	**FiT €/kWh**
Total Capital Grant cost, over 2018-2022 (€/MW)	**€ 36,419,166**		**€ 96,325,575**	
Average annual Capital Grant cost (€/year)	**€ 7,283,833**		**€ 19,265,115**	
Capital Grant cost per kWh produced (€/kWh)	**€ 0.02**		**€ 0.02**	
Total FiT Cost, over lifetime (€/kWh)		***€ 191,596,671***		**€ 471,342,025**
Average annual FiT cost (€/year)		***€ 7,663,866***		**€ 18,853,681**
Cost of FiT per kWh produced		***€ 0.08***		**€ 0.10**

Benefits				
CO2 emissions saved (tCO2)	**1,046,211**		**2,091,891**	
Value of CO2 emission saved (€/tCO2)	**€ 6,988,688**		**€ 13,973,833**	
Jobs creation (jobs/over lifetime)	**2,348**		**4,696**	

Impact of FIT on consumers	**Annual Average over lifetime**	**Annual Average over lifetime**
Annual total electricity consumption - Armenia, kWh	5,706,089,454	5,706,089,454
Total annual FiT cost - High Scenario	€ 7,983,195	€ 19,639,251
Cost per kWh consumed	€ 0.001	€ 0.003
Average retail electricity price (resid+non-resid) over the period €/kWh	€ 0.085	€ 0.085
Impact on average retail electricity price	€ 0.018	€ 0.043

Household consumption kWh/year	1550	1550
Impact on household bill €/year	**€ 2.17**	**€ 5.33**

Table 38: Summary cost benefit analysis results - Ukraine

Summary of Results - Ukraine				
PV capacity potential, MW (Component 3)	2513			
	Medium Scenario		**High Scenario**	
Estimated total installed capacity over 2018-2022 (MW)	**281**		**561**	
Total electricity produced over lifetime (kWh)	5,368,804,225		10,735,003,058	
Policy implemented	**Capital Grant €/MW**	**FiT €/kWh**	**Capital Grant €/MW**	**FiT €/kWh**
Total Capital Grant cost, over 2018-2022 (€/MW)	**€ 206,309,690**		**€ 456,552,592**	
Average annual Capital Grant cost (€/year)	**€ 41,261,938**		**€ 91,310,518**	
Capital Grant cost per kWh produced (€/kWh)	**€ 0.04**		**€ 0.04**	
Total FiT Cost, over lifetime (€/kWh)		***€ 893,207,125***		**€ 2,019,208,828**
Average annual FiT cost (€/year)		***€ 35,728,285***		**€ 80,768,353**
Cost of FiT per kWh produced		***€ 0.17***		**€ 0.19**

Benefits		
CO2 emissions saved (tCO2)	**4,332,625**	**8,663,147**
Value of CO2 emission saved (€/tCO2)	**€ 28,941,935**	**€ 57,869,825**
Jobs creation (jobs over lifetime)	**7,139**	**14,279**

Impact of FIT on consumers	**Annual Average over lifetime**	**Annual Average over lifetime**
Annual total electricity consumption - Armenia, kWh	126,212,822,385	126,212,822,385
Total annual FiT cost - High Scenario	€ 37,216,964	€ 84,133,701
Cost per kWh consumed	€ 0.000	€ 0.001

Average retail electricity price (resid+non-resid) over the period €/kWh	€ 0.086	€ 0.086
Impact on average retail electricity price	€ 0.004	€ 0.008
Household consumption kWh/year	2080	2080
Impact on household bill €/year	**€ 0.61**	**€ 1.39**

Table 39: Summary cost benefit analysis results - Moldova

Summary of Results - Moldova				
PV capacity potential, MW (Component 3)	67			
	Medium Scenario		**High Scenario**	
Estimated total installed capacity over 2018-2022 (MW)	**7**		**14**	
Total electricity produced over lifetime (kWh)	146,474,181		292,928,155	
Policy implemented	**Capital Grant €/MW**	**FiT €/kWh**	**Capital Grant €/MW**	**FiT €/kWh**
Total Capital Grant cost, over 2018-2022 (€/MW)	**€ 645,798**		**€ 4,194,575**	
Average annual Capital Grant cost (€/year)	**€ 129,160**		**€ 838,915**	
Capital Grant cost per kWh produced (€/kWh)	**€ 0.00**		**€ 0.01**	
Total FiT Cost, over lifetime (€/kWh)		***€ 12,188,696***		**€ 32,614,314**
Average annual FiT cost (€/year)		***€ 487,548***		**€ 1,304,573**
Cost of FiT per kWh produced		***€ 0.08***		**€ 0.11**

Benefits		
CO2 emissions saved (tCO2)	**76,313**	**152,616**
Value of CO2 emission saved (€/tCO2)	**€ 509,771**	**€ 1,019,472**
Jobs creation (jobs over lifetime)	**182**	**365**

Impact of FIT on consumers	**Annual Average over lifetime**	**Annual Average over lifetime**
Annual total electricity consumption - Moldova, kWh	6,152,118,010	6,152,118,010
Total annual FiT cost - High Scenario	€ 507,862	€ 1,358,930
Cost per kWh consumed	€ 0.000	€ 0.000

Average retail electricity price (resid+non-resid) over the period €/kWh	€ 0.087	€ 0.087
Impact on average retail electricity price	€ 0.001	€ 0.003
Household consumption kWh/year	1600	1600
Impact on household bill €/year	**€ 0.13**	**€ 0.35**

Table 40: Summary cost benefit analysis results - Belarus

Summary of Results - Belarus	
PV capacity potential, MW (Component 3)	1135
Estimated total installed capacity over 2018-2022 (MW)	**25**
Total electricity produced over lifetime (kWh)	448,543,543
Policy implemented	**FiT €/kWh**
Total FiT Cost, over lifetime (€/kWh)	**€ 43,186,576**
Average annual FiT cost (€/year)	**€ 1,727,463**
Cost of FiT per kWh produced	**€ 0.10**
Benefits	
CO2 emissions saved (tCO2)	**209,918**
Value of CO2 emission saved (€/tCO2)	**€ 1,402,255**
Jobs creation (jobs/over lifetime)	**636**
Impact of FIT on consumers	**Annual Average over lifetime**
Annual total electricity consumption - Belarus, kWh	36,538,553,749
Total annual FiT cost	€ 1,799,441
Cost per kWh consumed	€ 0.00005
Average retail electricity price (resid+non-resid) over the period €/kWh	€ 0.086
Impact on average retail electricity price	0.065%
Household consumption kWh/year	1,933
Impact on household bill €/year	**€ 0.10**

Table 41: Summary cost benefit analysis results - Azerbaijan

Summary of Results - Azerbaijan	
PV capacity potential, MW (Component 3)	1412
Estimated total installed capacity over 2018-2022 (MW)	**5**
Total electricity produced over lifetime (kWh)	112,677,150
Policy implemented	**FiT €/kWh**
Total FiT Cost, over lifetime (€/kWh)	**€ 10,753,771**
Average annual FiT cost (€/year)	**€ 430,151**
Cost of FiT per kWh produced	**£0.10**

Benefits	
CO2 emissions saved (tCO2)	**58,705**
Value of CO2 emission saved (€/tCO2)	**€ 392,148**
Jobs creation (jobs/over lifetime)	**127**

Impact of FIT on consumers	**Annual Average over lifetime**
Annual total electricity consumption - Azerbaijan, kWh	21,408,894,024
Total annual FiT cost - 1000 rooftop	€ 448,074
Cost per kWh consumed	€ 0.000
Average retail electricity price (resid+non-resid) over the period €/kWh	€ 0.085
Impact on average retail electricity price	€ 0.000
Household consumption kWh/year	2966
Impact on household bill €/year	**€ 0.06**

6 Grid impact

PV technology comprises a promising distributed generation technology which is suitable to be located in cities since it is clean, quiet and nearly maintenance free. As distributed generation, it has the potential of benefiting the system by reducing transmission and distribution losses. Its integration however at increased volumes to the distribution network may bring changes in the planning and operational status quo of the overall power system.

Quantification of electricity market & grid issues has not been possible and has not been included in the above analysis, neither as costs nor as benefits, because of the inexistent quantification data by network operators. However, a qualitative discussion of possible impacts is presented in accordance to section 2.4 of the Component 1: “Review of EU Experience with Solar PV in buildings” report. Based on this review of EU experiences and for the purposes of assessing the impact of introducing PV in buildings in Armenia, Azerbaijan, Belarus, Moldova and Ukraine we will present in what follows a qualitative evaluation of the main grid issues and implications associated with building-PV deployment in those countries.

For the purposes of this section we have worked and got detailed grid data from Moldelectrica, the Moldovan TSO. These data enabled us to develop a better (compared to the remainder EaP countries) understanding on the hosting capacity aspect both at aggregated system and at city level. We therefore present the relevant Moldovan results here as a showcase example for the nature of assessment required to be performed by all countries. It is worthwhile to be mentioned however that the analysis below is only indicative and serves the purpose of introducing the subject to the national decision makers. A proper assessment of the RES integration impact assessment would require a closer look on the below aspects at a national level and would involve a greater level of detail both in terms of data and system modelling at transmission and distribution level.

6.1 Hosting capacity

The first issue that needs to be addressed is hosting capacity. Hosting capacity is determined (in order of severity) by voltage rise on the feeders on which PVs are connected, cable loading and transformer capacity. All three above criteria need to be addressed at distribution level and in our case at each specific city level. In the region addressed in this study however, a consolidation of the role of the DSO in the manner provided by the Third Energy Package is not yet in place. The distribution companies carry out both the distribution and supply activities in a bundled manner. Therefore, there is neither an obligation nor and incentive placed on the distribution companies to plan their networks for maximum penetration of RES-based distributed generation. Pursuant to the above we haven’t been able to identify any study carried out by or on behalf of the distribution companies addressing this issue. On the legal and institutional side, the countries either spontaneously (i.e. non Energy Community Treaty Contracting Parties) or based on a compliance to the EU Acquis programme (i.e. Energy Community Treaty Contracting Parties) take actions to support the development of their national legislative and regulatory framework in order to enable electricity from renewable energy sources to feed into the national power grid. We haven’t been able to identify however any published reference of a study that includes a specific assessment of the hosting capacity any distribution region in the countries addressed in this report.

Since the issue is not found to be adequately addressed at distribution level, hosting capacity assessments at an aggregated level (transmission) where sought to be evaluated. In addition, GSE, the Georgian TSO which was our primary point of contact in “Quantification of the potential of building-PVs in Georgia and the rest of the Eastern Partner countries” report of this study, we have contacted and discussed the grid impact issues with Moldelectrica, the Moldovan TSO and Ukrenergo, the Ukrainian TSO. For the remainder countries the information and assessment provided below is mostly based on local experts’ feedback and published references.

6.1.1 Armenia

There are no specific hosting capacity calculations in Armenia either at system (transmission) or at distribution level. The scaling up renewable energy investment plan (SREP) for Armenia which was developed with the assistance of Renewable Energy and Energy Efficiency (R2E2) fund provides capacity figure which are referred to as potential in the SREP report[6] and as targets to 2020 in the Energy Charter’s In-Depth Review of the Energy Efficiency Policy of Armenia[7] (2017-page 96). For the case of decentralised PV, the respective capacity figure is 1300 MW.

6.1.2 Azerbaijan

There are no specific hosting capacity calculations in Azerbaijan either at system (transmission) or at distribution level. The “Review of EaP Countries Experiences with Building PVs” report of this study indicates a target of 50 MW for solar PV (both utility scale and decentralised) by 2020.

6.1.3 Belarus

There are no specific hosting capacity calculations in Belarus either at system (transmission) or at distribution level. The “Review of EaP Countries Experiences with Building PVs” report of this study indicates a target of 250 MW for solar PV (both utility scale and decentralised) by 2020 whereas the quota under which solar PV may be granted national support via the FiT is 15 MW in the period 2016-2018 (i.e. 5 MW annually).

6.1.4 Moldova

Hosting capacity and the residual load curve are in reality not isolated aspects since the later at a substation/transformer comprises the first metric describing the impact of variable RES generation injection to the grid. In further steps of the hosting capacity determination the residual load curve may be used as the basis for the calculation of feeder loading and voltage rise which also comprise important elements of the overall hosting capacity assessment exercise.

Since we haven’t been able to look at the feeder loading and voltage rise in our short analysis it is preferable that our partial and preliminary assessment on the hosting capacity to be presented in the discussion of the residual curves below. It is worthwhile however to be mentioned at this point the Moldelectrica expects that with condition of the grid around 1000 MW of RES would be able to be accommodated at a transmission wide system level.

6.1.5 Ukraine

Hosting capacity calculations in Ukraine were not possible but our discussion with the Ukrainian TSO – Ukrenergo - revealed that the generally accepted limit of all variable renewable energy

[6] https://dhinfrastructure.com/wp-content/uploads/2015/04/Armenia-SREP-Investment-Plan_final.pdf
[7] http://www.energycharter.org/fileadmin/DocumentsMedia/EERR/ARMENIA_IDR_2017_Final_EN.pdf

(VRE) generation is around 4.5 GW. This cumulatively includes both wind and solar power capacities for which Ukrenergo assumes a foreseeable (based on current trends) breakdown of 2 GWp for PV and 1.5 GW for wind. So far 400 MW wind and 600 MW (cumulatively 1 GW VRE) have been connected at the transmission system of Ukraine and there are connection offers for an additional 4.2 GW (2.8 GW of wind and 1.4 GW of PV). Overall, the anticipated penetration margin appears reasonable (ca. 16%) compared to the 27.845 MW (ca. 27.8 GW) peak demand which was recorded in 2016. The draft TYNDP of Ukraine 2017-2026[8] which was prepared by Ukrenergo and approved by the Ministry of Energy and Coal Industry comes up with a rather different RES development scenario[9] which in turn is taken as a basis for the elaboration of the production/supply balance and subsequent network development scenarios

Table 42: Expected RES capacities in Ukraine (source: TYNDP 2017-2026)

Джерело/ рік	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Wind	440	450	1085	1382	1640	1670	1700	1720	1740	1760	1780	1790
PV	365	375	1094	1393	1655	1680	1700	1720	1740	1760	1780	1790
Biomass	60	70	450	580	686	700	720	745	770	800	830	840

The Ukraine Sustainable Energy Lending Facility (USELF) which is an investment facility established by the EBRD reports[10] on their estimates of hosting capacity per "oblast" which is a region in Ukraine which each region been connected with power lines of a voltage level of 220 kV and above (i.e. transmission level). The study finds that the transfer capabilities between oblasts are sufficient to accommodate large VRE capacity addition which however are overall not realistic from an operational point of view (prominently due to the lack of flexibility in the Ukrainian power system. Therefore, the study considers "Regional Development Scenarios for Wind Only, Solar Only and Combined Wind and Solar Scenarios" based on the assumption "that the renewable resource is either limited by the availability of the resource in the region or by the load in the immediate region that can consume the energy, whichever is lower."

More specifically, the USELF study suggests that:

- The overall "Central" region, which includes but does not limit to Kyiv, could accommodate 1800 MW of PV in the Solar Only scenario or 571 MW of PV in the Regional Development Combined scenario;
- The overall "Southern" region, which includes but does not limit to Odessa, could accommodate 1281 MW of PV in the Solar Only scenario or 320 MW of PV in the Regional Development Combined scenario;

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[8] Page 61, https://ua.energy/wp-content/uploads/2016/12/Proekt-Planu-rozvytku-OES-Ukrayiny-na-2017-2026-roky.pdf
[9] We note that a grid-level assessment is available only in Georgia and Ukraine by means of their respective TYNDPs
[10] http://www.uself.com.ua/fileadmin/uself-ser-en/3/E%20-%20Transmission.pdf

- The overall "Western" region, which includes but does not limit to Lviv, could accommodate 0 MW of PV in the Solar Only scenario or 0 MW of PV in the Regional Development Combined scenario due to solar resource limitations[11];
- The overall "Dnipro" region, which includes but does not limit to Zaporizhia, could accommodate 3980 MW of PV in the Solar Only scenario or 1001 MW of PV in the Regional Development Combined scenario;

In comparison our own estimates on building-PV capacities based on the Component 3: "Quantification of the potential of building PVs in Georgia and the rest of the Eastern Partner countries" report of this study are presented below for both the "**theoretical"** and the "**expected"** estimates as they are defined below in section 6.2

Table 43: Building PV capacities per city in Ukraine (source: own analysis)

	Theoretical installed capacities (MW)			Expected installed capacities (MW)		
City	**Residential**	**Non-residential**	**Total**	**Residential**	**Non-residential**	**Total**
Kyiv	3,983	488	**4,471**	797	488	**1,285**
Odessa	2,040	322	**2,362**	408	322	**730**
Lviv	599	142	**741**	120	142	**262**
Zaporizhia	524	237	**761**	105	237	**341**
Total	**7,680**	**1,189**	**7,770**	**1,429**	**1,189**	**2,618**

Apparently our theoretical estimates are beyond the overall margins considered by Ukrenergo for the whole system. Nevertheless, our respective expected estimates are – with the exemption of Lviv and partially (i.e. Solar Only Scenario) compatible to the USELF estimates. It is worthwhile to be noted however that our estimates refer to building-PV installations and therefore they need to be considered in conjunction with 1.4 GW plants with connection offer as mentioned above.

6.2 Residual load curve

6.2.1 Moldova

Demand-side analysis

Moldelectrica provided for the purposes of this brief analysis two data sets following our request:

- a full year of load data series (i.e. 8760 measurements) assessment of the system residual load curve;

[11] The study refers to utility scale solar PV and mentions that "The solar resource potential is not optimal in the region and mountainous terrain would make utility-scale solar development challenging".

- a full year of load data series for selected transformers located at substations comprising the interface between the transmission and distribution networks[12] around the cities of Chisinau, Balti and Cahul.
- The data provided for the annual operation of the above transformers were 15-min intervals which where averaged to develop the characteristic daily profiles presented below. Moreover, in order to produce the equivalent capacities at city level active power injections and withdrawals per interval were aggregated to produce a unique equivalent capacity figure representing the city as a single node.

Table 44: Chisinau, Balti, Cahul "bulk supply points" characteristics (source: Moldelectrica)

City	Substation name	Transformer type/capacity
Chisinau	SS Chisinau 330 kV	2 autotransformers of 200 MVA
	SS Strasseni 330 kV	2 autotransformers of 200 MVA
Balti	SS Balti Centru 110 kV	2 transformers of 16 MVA (planned to be replaced with 2x25MVA)
	SS Selimas 110 kV	2 transformers of 25 MVA
	SS Balti 330 kV	3 autotransformers 200 MVA (the actual load to Balti goes through 3-rd winding which has the capacity of 63 MVA)
Cahul	SS Cahul Nord 110 kV	2 transformers of 16 MVA
	SS Cahul Sud 110 kV	2 transformers of 16 MVA
	SS Cahul Sok 110 kV	2 transformers of 6.3 MVA

Supply-side analysis

On the supply side we have used Renewables.ninja[13] utility. Renewables.ninja is a web tool developed by Imperial College London and ETH Zürich that shows the estimate amount of energy

[12] Referred to as bulk supply points in certain jurisdictions' grid code terminology
[13] https://www.renewables.ninja/

that could be generated by wind or solar farms at any location[14]. While we strongly recommend that for operational purposes TSOs use RES forecasting models and techniques based on their detailed requirements and real/time-tested weather forecast tools, renewables.ninja served excellently for the analysis carried out for the purposes of this report.

Moreover, for us the hourly output of PV generation on an annual basis was the basic rationale for using renewables.ninja whereas we were much more confident on the annual yields calculated on the basis of synthetic climate files in the "Quantification of the potential of building PVs in Georgia and the rest of the Eastern Partner countries" report of this study. Furthermore, having a solid idea on the installed capacity figures our use of the renewables.ninja aimed to derive an hourly factor describing the kW output or a single installed kWp in each city. Therefore, conditioning the performance ratio of each city-specific "model system" (with a 1 kWp installed capacity) we have been able to derive the so-called **specific production factor (kW/kWp)** for each hour of the year in each city. Multiplying this specific production factor with the installed capacity in each city or aggregated at system level we could then derive an **hourly PV output** to compare with the hourly demand data provided by Moldelectrica.

As it can be seen from the hourly output rates, for the typical 1kW PV unit, the maximum hourly output for Chisinau is 0.823 kW, for Balti 0.809 kW and for Cahul 0.849 kW.

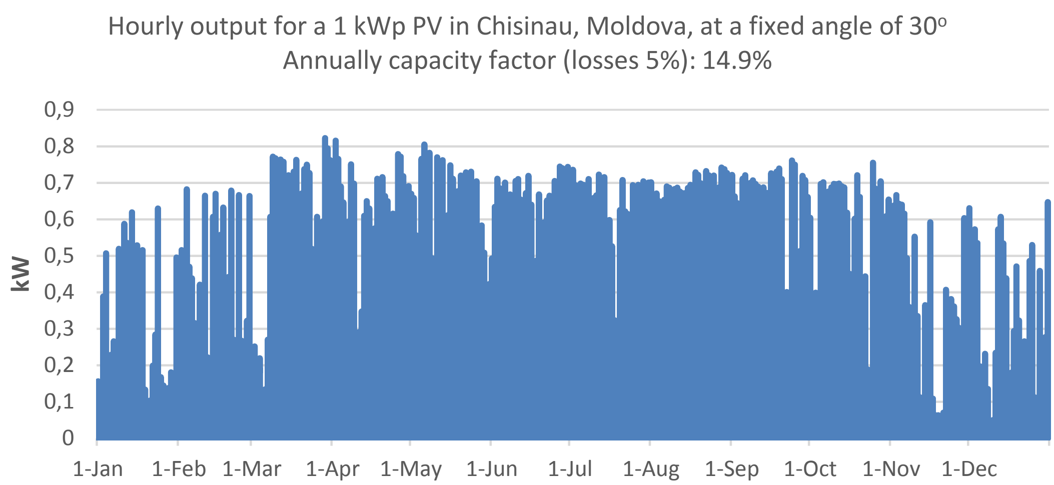

Figure 6: Specific output (kW/kwp) in Chisinau (Renewables.ninja,2014)

[14] It is worthwhile to mention, that after the development of our residual curve analysis we also became aware of EMHIRES dataset which provides RES-E generation time series for the EU-28 and neighbouring countries (https://setis.ec.europa.eu/related-jrc-activities/jrc-setis-reports/emhires-dataset-part-ii-solar-power-generation).

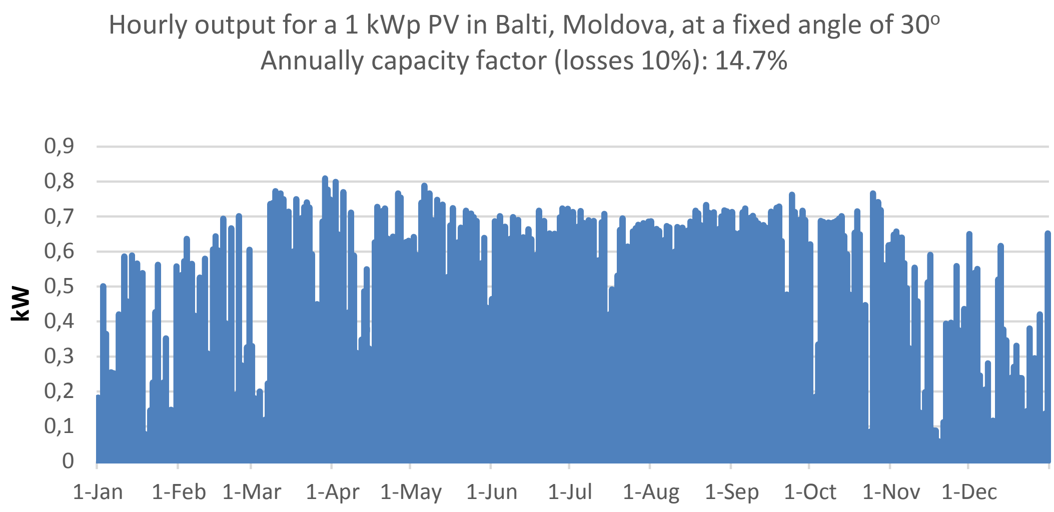

Figure 7: Specific output (kW/kwp) in Balti (Renewables.ninja,2014)

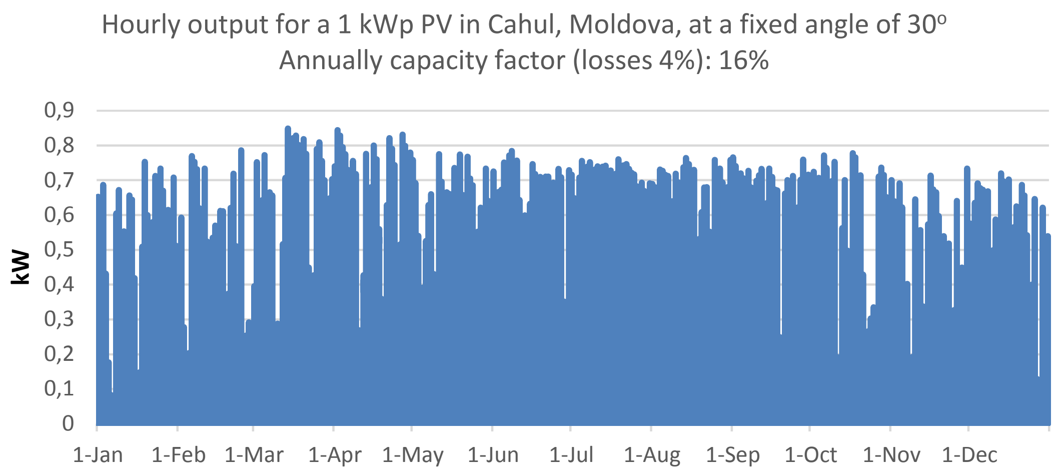

Figure 8: Specific output (kW/kwp) in Cahul (Renewables.ninja,2014)

Conditioning the renewables.ninja output to match our own estimates as calculated by the RETScreen Tool, for data based on Typical Meteorological Years in the "Quantification of the potential of building PVs in Georgia and the rest of the Eastern Partner countries" report involved a selection over the city-specific "model system". Our RETScreen-based figures are monthly based, whereas the renewables.ninja output is hourly. We have verified our assumptions for renewables.ninja output by comparing the specific annual yields and capacity factors respectively between the monthly and hourly outputs for each city. The results of this verification exercise are presented below on Table 45:

Table 45: Verification indices for the use of hourly PV output data (source: own analysis)

City	Chisinau		Balti		Cahul	
	Hourly	Monthly	Hourly	Monthly	Hourly	Monthly
Annual capacity factor	14,9%	13.8%	14,7%	13,4%	16,1%	16,2%

Specific Annual Yield (kWh/kWp/y)	1207 - 1240	1287	1288	1172	1413	1419

To complete the supply side analysis, we need to define the installed capacities at city level and further on aggregate them, in order to come up with a single system level figure. In the Component 3: "Quantification of the potential of building PVs in Georgia and the rest of the Eastern Partner countries" report we have worked this out considering two gross market segments namely the residential and non-residential one. The calculated capacities involved assumptions and constraints related to the orientation, tilt and available space for the installation of the rooftop PV systems. However, it is estimated that while these capacities may actually be realised by a certain degree of confidence for the non-residential sector, a further reduction by ca. 80% should be considered for the residential sector based on international experience. This is based on a series of studies conducted, in various parts of the world, assessing the total rooftop area available for PV deployment[15].

As those studies showed, the parameters that affect the availability can be classified in three main groups, namely (1) Density of the built environment, (2) Competitive uses of the roof and (3) Structural and regulatory issues.

Careful examination of evidence gathered through interaction with local experts and stakeholders on the quality of the building stock in all countries around the Black Sea and Caspian, has highlighted some important constructional and typological criticalities, which further reduce the total installation potential on Georgian cities roofs. Sloped roofs in single family and small residential house are of corrugated steel sheets, supported by wooden beams, resting on non-bearing walls: this leads to limited bearing capacity of the roofs, the lack of adequate structural support for the PVs and the difficulty in ensuring effective water tightness. Therefore, it has been estimated that the constraint factor of 80% has to be applied to the overall total PV capacity of single family houses/sloped roof potential. In other words, the constrained capacity potential cannot exceed 20%[16] of the total capacity estimated.

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[15] L.Bergamasco, P.Asinari, Scalable methodology for the photovoltaic solar energy potential assessment based on available roof surface area: Application to Piedmont Region (Italy), Solar Energy 85 (2011) 1041–1055

K.Mainzer, S.Killinger, R.McKenna..W.Fichtner. Assessment of rooftop photovoltaic potentials at the urban level using publicly available geodata and image recognition techniques, Solar Energy 155 (2017) 561–573

M.S.Wong et al., Estimation of Hong Kong's solar energy potential using GIS and remote sensing technologies, Renewable Energy 99 (2016) 325e335

S.Izquierdo, M.Rodrigues, N.Fueyo, A method for estimating the geographical distribution of the available roof surface area for large-scale photovoltaic energy-potential evaluations, Solar Energy 82 (2008) 929–939

J.Khan, M. Hassan Arsalan, Estimation of rooftop solar photovoltaic potential using geo-spatial techniques: A perspective from planned neighborhood of Karachi, Pakistan, Renewable Energy 90 (2016) 188-203

Theodoridou I., Karteris M., Mallinis G., Papadopoulos A.M. and Hegger M., Assessment of retrofitting measures and solar systems' potential in urban areas using Geographical Information Systems: application to a Mediterranean city, Renewable & Sustainable Energy Reviews (2012), 16, 6239–6261

Karteris M., Slini T. and Papadopoulos A.M., Urban solar energy potential in Greece: A statistical calculation model of suitable built roof areas for photovoltaics, Energy and Buildings (2013), 62, 459-468

[16] A recent (2016) study by the National Renewable Energy Laboratory (NREL) in the US proposes, for the much more favourable US market, a 26% respective figure when considering "small buildings" (https://www.nrel.gov/docs/fy16osti/65298.pdf)

Hence, we use the term **"theoretical"** to refer to the capacities calculated without the additional reduction factor for the residential segment and the term **"expected"** to distinguish the capacities on which a 80% further reduction factor has been imposed. The respective PV installed capacity figures are presented below on while the terms theoretical/expected PV output and/or residual curve may be construed accordingly based on the above definition.

Table 46: Building PV capacities per city in Moldova (source: own analysis)

	Theoretical installed capacities (MW)			Expected installed capacities (MW)		
City	**Residential**	**Non-residential**	**Total**	**Residential**	**Non-residential**	**Total**
Chisinau	142.8	29.5	**172.3**	28.56	29.5	**58.06**
Balti	17.5	3.4	**20.9**	3.5	3.4	**6.9**
Cahul	4.5	1	**5.5**	0.9	1	**1.9**
Total	**164.6**	**34**	**198.6**	**32.92**	**34**	**66.92**

System level analysis

Having the hourly PV output determined as described above we can now develop the residual load curve at system level using the difference between the hourly system load and the aggregated hourly PV output. In our case we can produce the "theoretical" system residual curve based on the total calculated PV capacity in the three cities and also the "expected" system residual curve in which the installed capacity of the residential segment is restrained to 20% of the originally calculated. Moreover, it needs to be pointed out that the system residual curve assumes[17] that the system is able to accommodate all PV injections at all times and that there are no congestions or other limiting factors leading to PV output curtailment (i.e. "copper plate" assumption). The chronological representation of the load and residual curves is presented below in Figure 9.

[17] Another important feature which is relevant for the Moldovan system and many others and which is neglected in our analysis due to lack of data is the system must-runs. The system must-runs are added to the PV output for the purposes of the residual curve analysis.

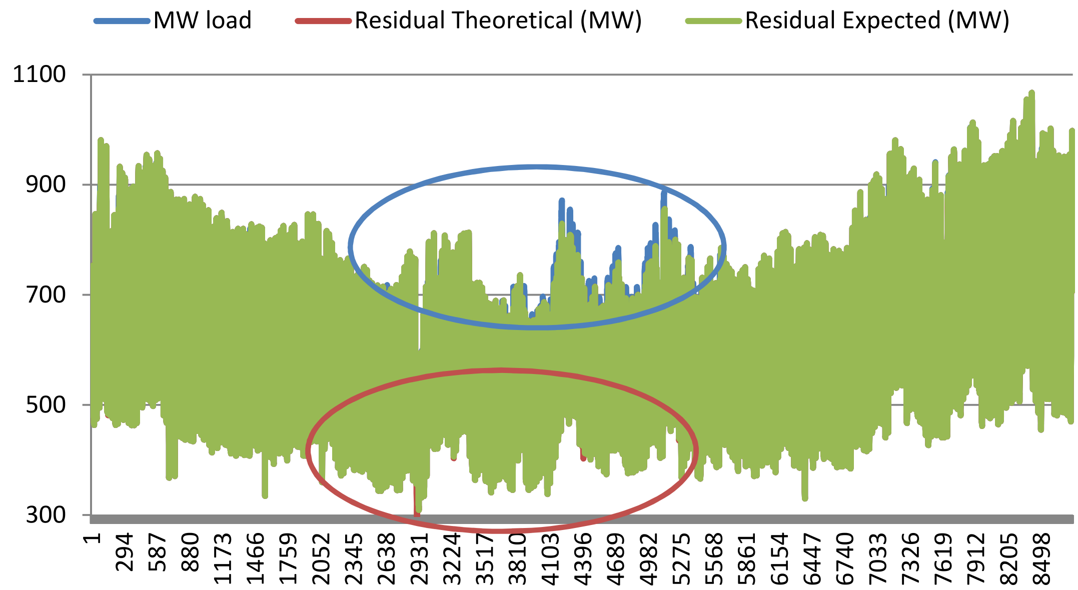

Figure 9: Load and residual curves (own analysis based on Moldelectrica and Renewables.ninja data)

Evidentially, the introduction of building-PV capacities as they are calculated in this study does not have a significant effect on the Moldovan system. This is evident by the fact that in the majority of the year the Residual Expected Load is almost identical with the system load. Two areas deserving attention in the above chart are marked by a blue and red circle. During the hours of the year enclosed by the blue circle we can witness the effect of the expected PV production which actually becomes noticeable in certain hours of the year and effectively reduces the system load (by some 50 MW or more in some cases). The fact that we do not see the red line indicating the Residual Theoretical indicates that this is always lower (i.e. reduces more the system load) from the Residual expected. Conversely, during low load conditions of the system the Residual Expected curve is not noticeable and therefore does not seem to seem to create any operational challenges[18] on Moldova's interconnection scheduling. There are only a few cases that such a system condition develops but this is unlikely since it happens only in respect of the Residual Theoretical as it is indicated by the red circled area.

Even these relatively insignificant intervals for which the system seems to deviate from is expected operation leads us to investigate further the characteristic snapshots of supply/demand balance which in turn represent system extremes or "stress-hours" and they include:

- The 2nd May 2016 in which the Moldovan system reached its lowest demand (309 MW)
- The 16th December 2016 in which the Moldovan system reached its peak demand (1067 MW)
- The 28th March in which the Theoretical[19] PV output reaches its annual maximum (162.5 MW)

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[18] Unless due care is taken by the TSO, during surplus hours the nominated interconnection schedules would have been affected by the excess PV production.
[19] The respective "expected" value is anticipated on the same day and hour although reduced as it is discussed earlier on this section.

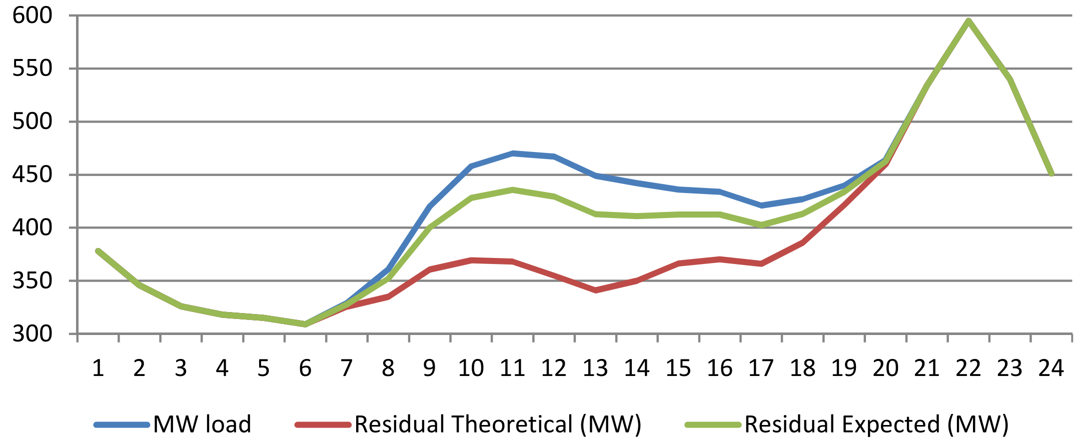


Figure 10: Moldova System Load and Residual Load Curves at Low Load Conditions (2 May 2016)

The above plot of the system load and residual curves for low demand conditions reveal the prominent “duck curve” which is often encountered in power systems with high PV penetration. In our case this is caused by the combination of the relatively high PV output and the low system demand.

It is also interesting to see the evolution of the system demand during the same day in combination with the PV output. This is useful in making a preliminary judgement of the ramping needs i.e. ramp down and up regulation of other dispatchable units with sufficient ramping capabilities during sunrise and sunset, respectively. For example, as it is shown in Figure 11: below PV output is helpful for the system in the morning and up to 13:00 but then as the PV output fades away generating units (or interconnection schedules) should be able to cutter for the increasing demand which peaks at 22:00 in the evening.

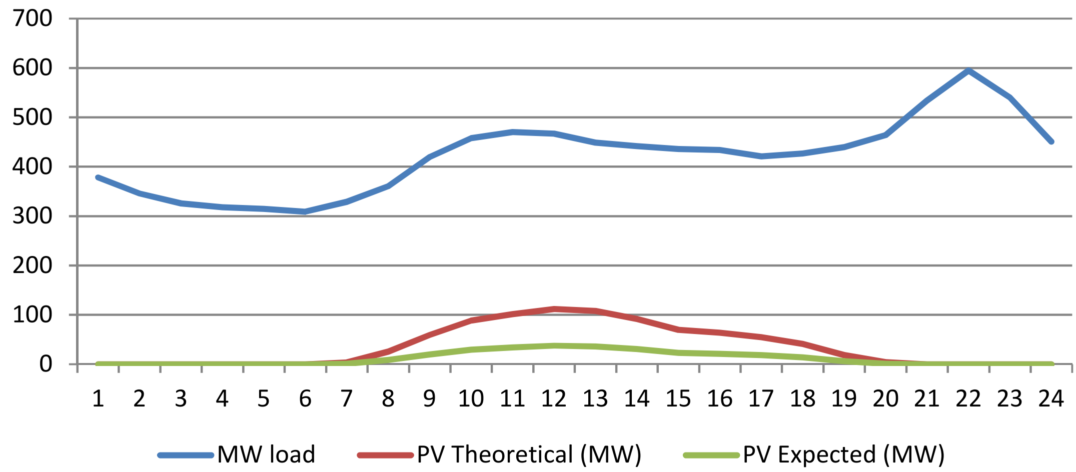


Figure 11: PV Production Curves at Low Load Conditions (2 May 2016)

Looking at the PV output effect during the peak demand day of 2016 in the Moldovan system the impact is almost negligible – a fact that is apparent by both the residual curves and the comparison of the system load with the respective PV output shown in Figure 12 and Figure 13, respectively.

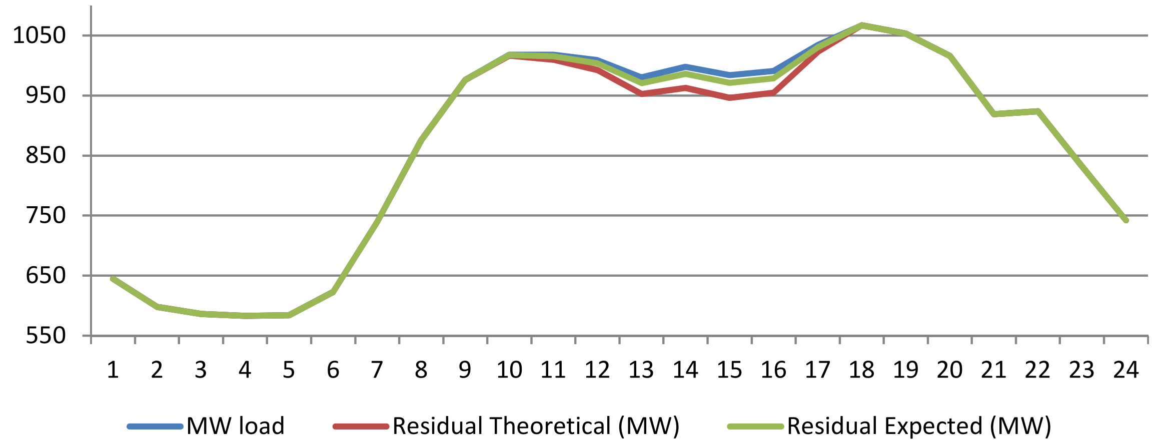


Figure 12: Moldova System Load and Residual Load Curves at Peak Load Conditions (16 December 2016).

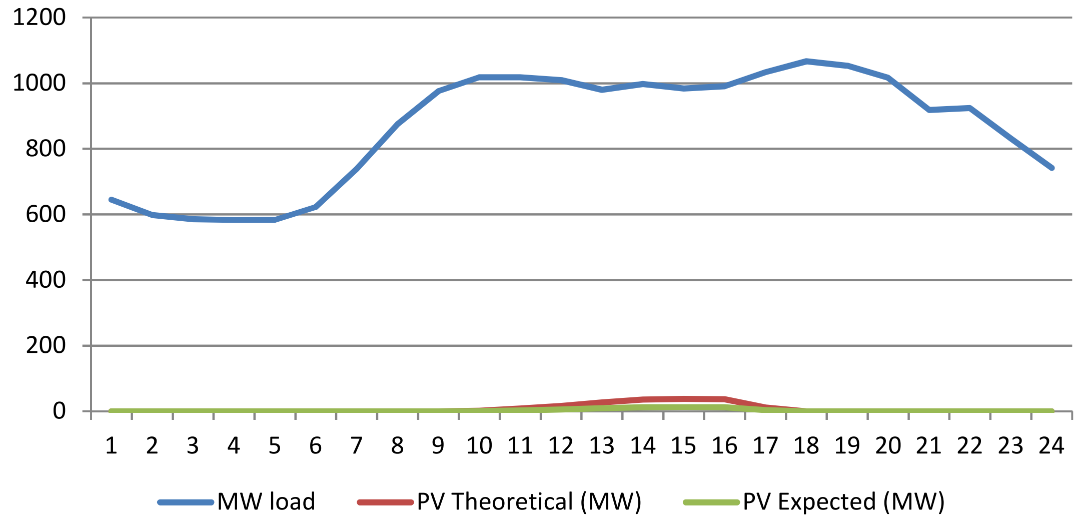


Figure 13: PV Production Curves at Peak Load Conditions (16 December 2016)

Last but not least, we may take a look on the absolute PV production output effect which in our exercise happens at 28 March. Not surprisingly the PV system reaches its peak output in climate conditions that are characterised by the combination of high insolation and relatively cool temperatures which help the PV temperature derating factor to be minimised.

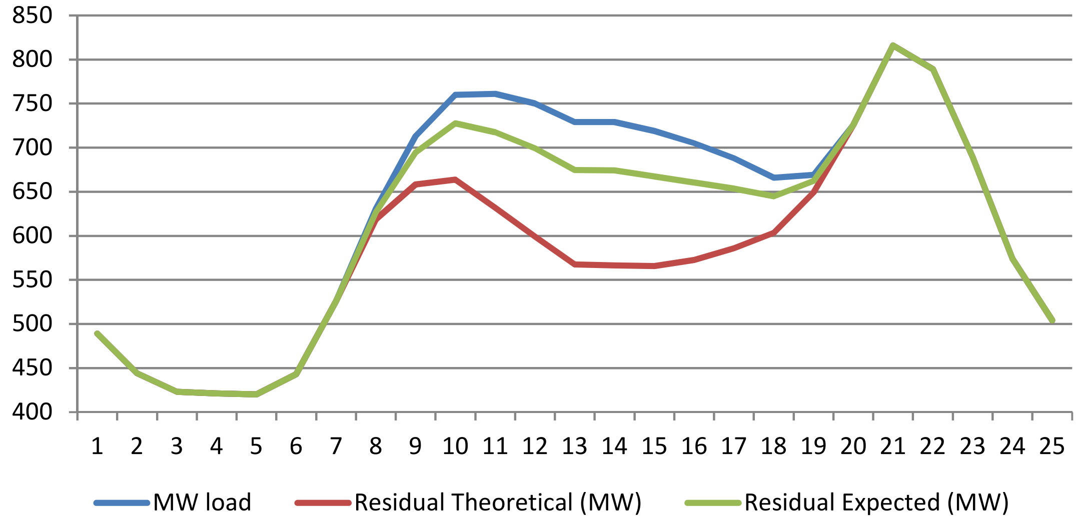


Figure 14: Moldova System Load and Residual Load Curves at Peak PV Output Conditions (28 March 2016)

Here as anticipated we can observe the duck curve in its maximum whereas the effect of the demand reduction partially coincides with the morning low peak in the spring time daily demand curve of the Moldovan power system (see also Figure 15 below). Nevertheless, the effect even in this day when the PV output is expected to reach its max contribution is at the order of 50 - 60 MW (considering the expected PV output) and can thereby be deemed as manageable by the Moldovan TSO.

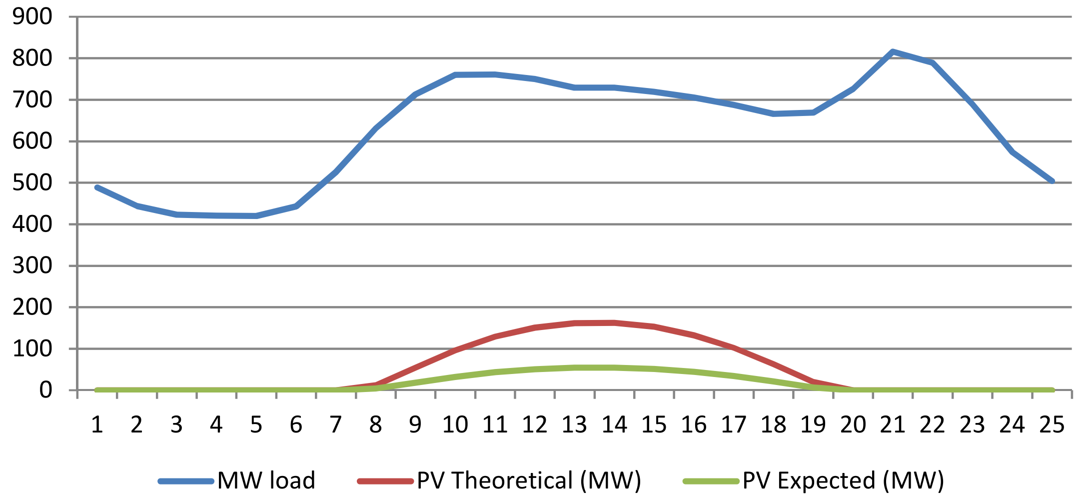


Figure 15: PV Production Curves at Peak PV Output Conditions (28 March 2016)

City level analysis

As also discussed earlier on in this section we can perform a similar analysis at city level by comparing the respective city theoretical and expected PV outputs with the demand at city level provided by aggregation of substation and transformer data as it is show above on

Table 44. In this case however we would particularly be looking for hours in the year where PV output may exceed the city level demand – "spilling" thus PV-generated power to the rest of the

Moldovan network. For ease of reference we user the same snapshot days as in the country-level analysis presented above.

Chisinau

For Chisinau which comprises the biggest load centre in the country the effect of PV introduction at levels considered by this study appears to be similar to that discussed in the country-level analysis presented above.

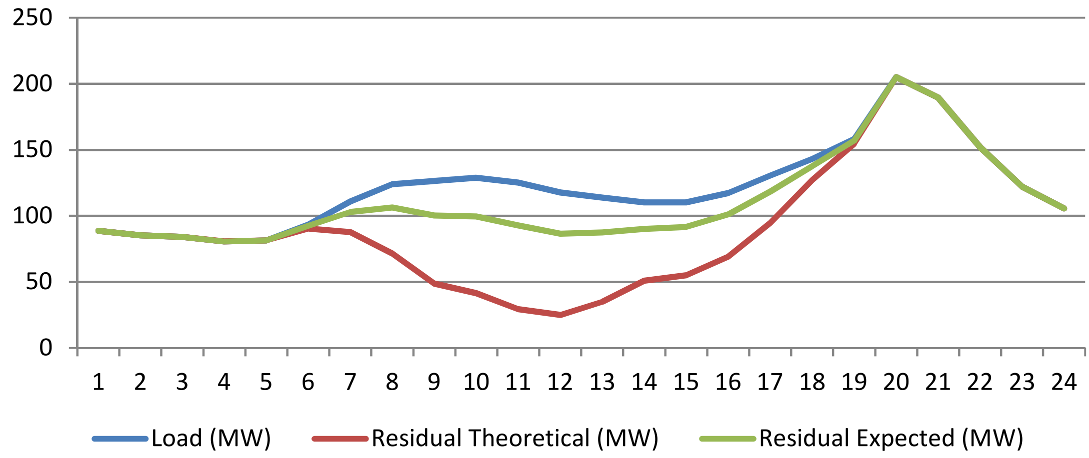


Figure 16: Chisinau Load and Residual Load Curves at Low Load Conditions (2 May 2016)

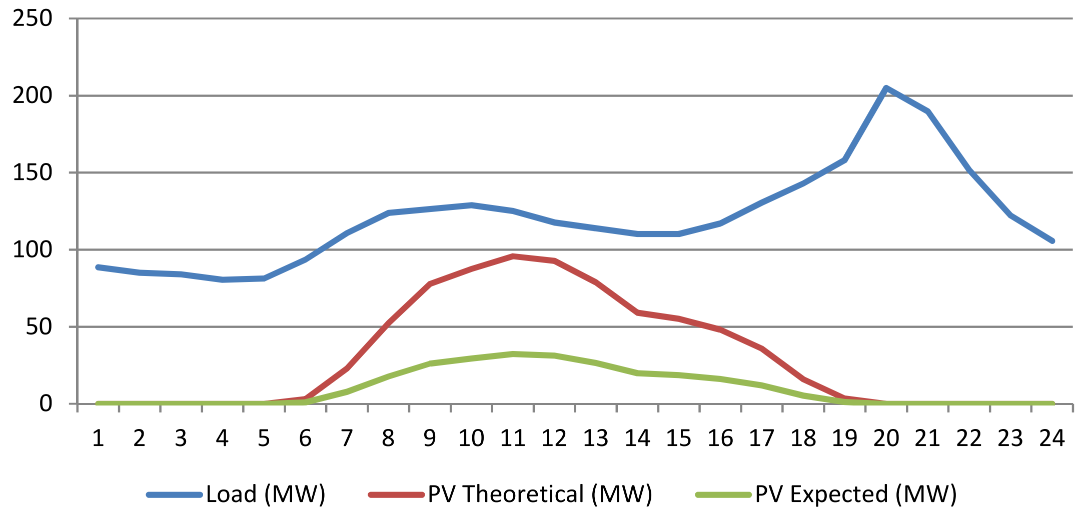


Figure 17: Chisinau PV Production Curves at Low Load Conditions (2 May 2016)

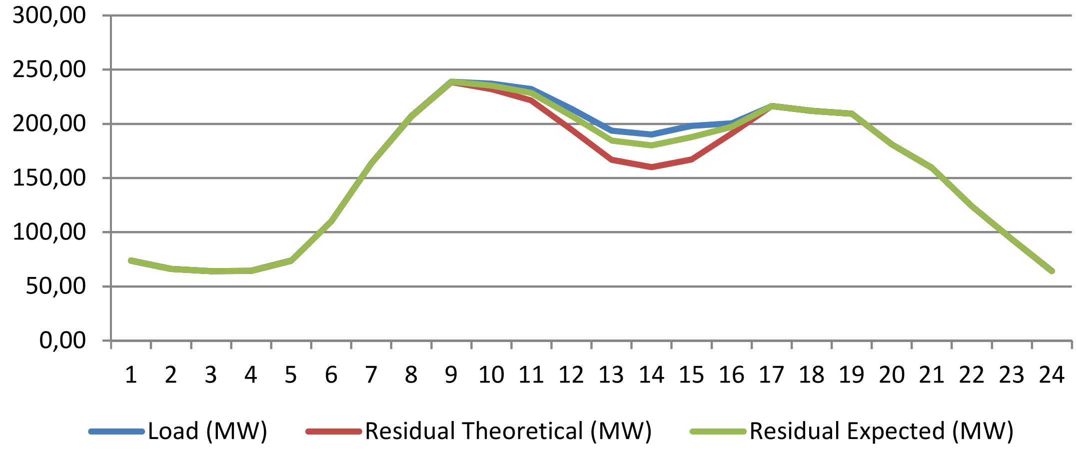


Figure 18: Chisinau Load and Residual Load Curves at Peak Load Conditions (16 December 2016)

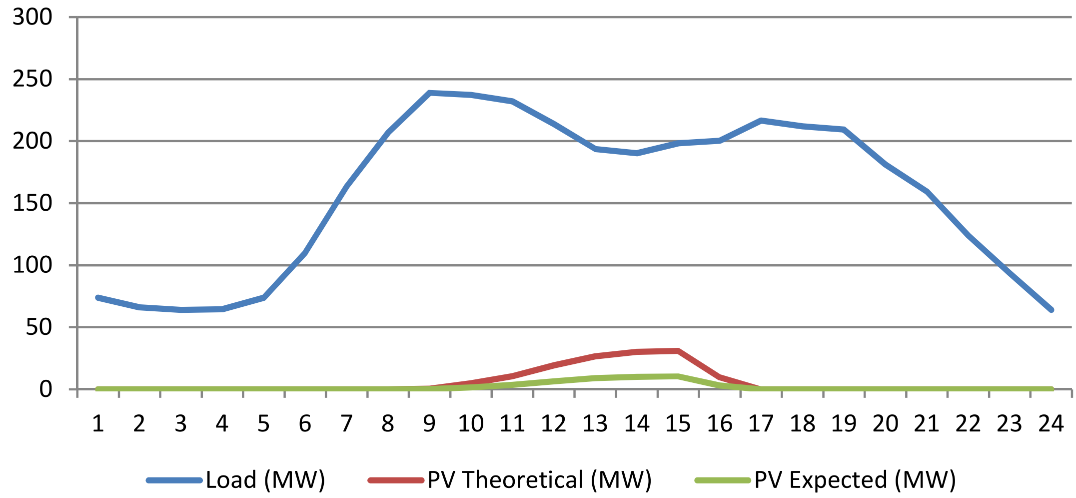


Figure 19: Chisinau PV Production Curves at Peak Load Conditions (16 December 2016)

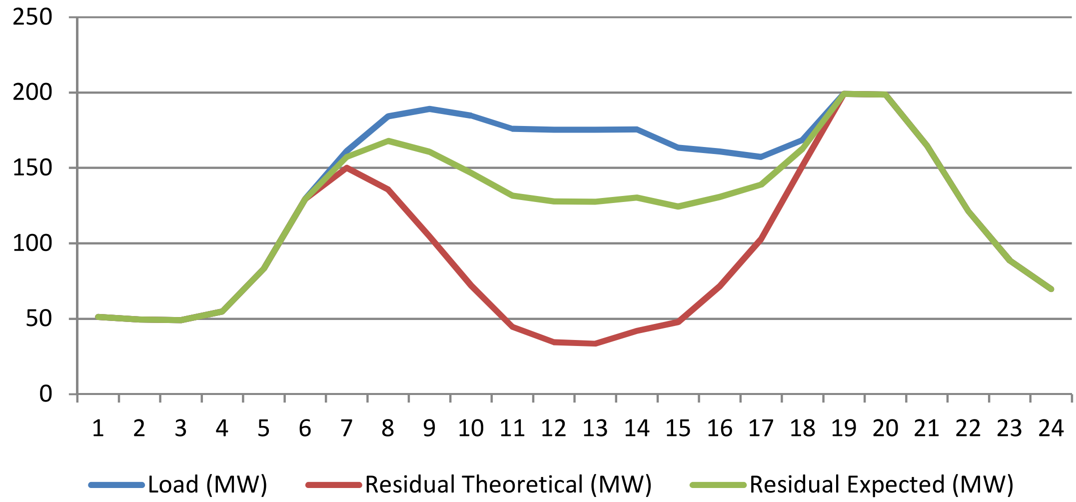


Figure 20: Chisinau Load and Residual Load Curves at Peak PV Output Conditions (28 March 2016)

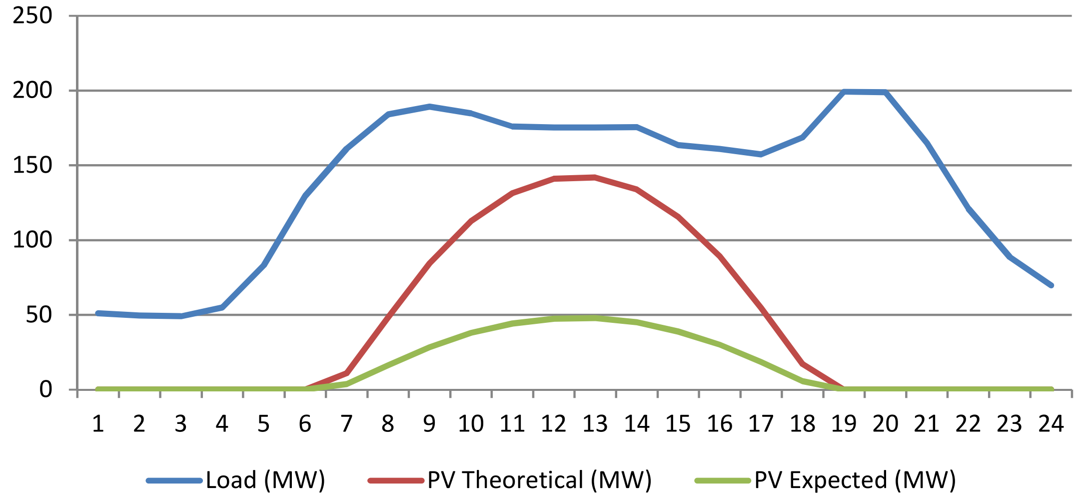


Figure 21: Chisinau PV Production Curves at Peak PV Output Conditions (28 March 2016)

Balti

Balti is a much smaller city than Chisinau and the PV capacity to be installed is likewise much less (even at the order of a tenth in the case of the "expected" PV capacities. However, the effect of the introduction of building-PVs in the city is noticeable without however reaching the point of "exporting" to the Moldovan grid at any time throughout the year.

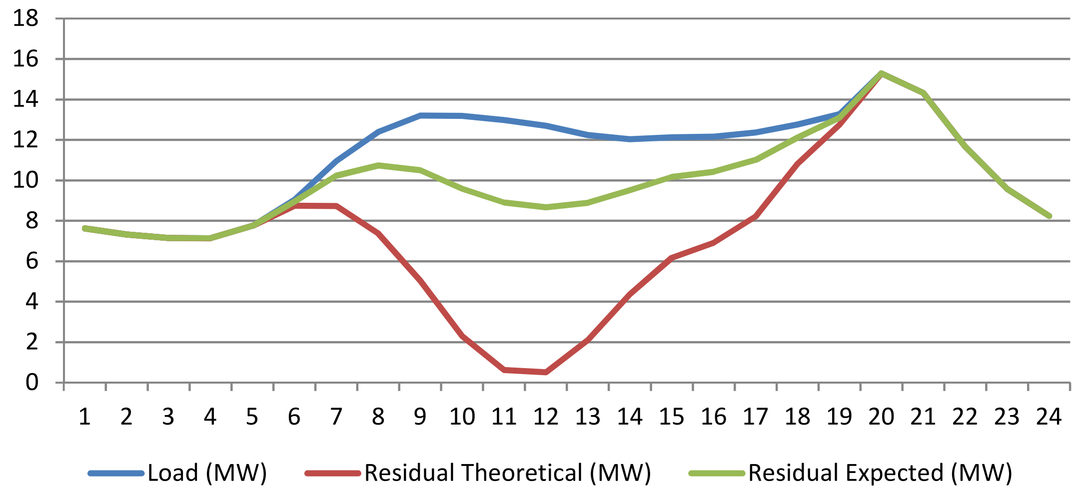


Figure 22: Balti Load and Residual Load Curves at Low Load Conditions (2 May 2016)

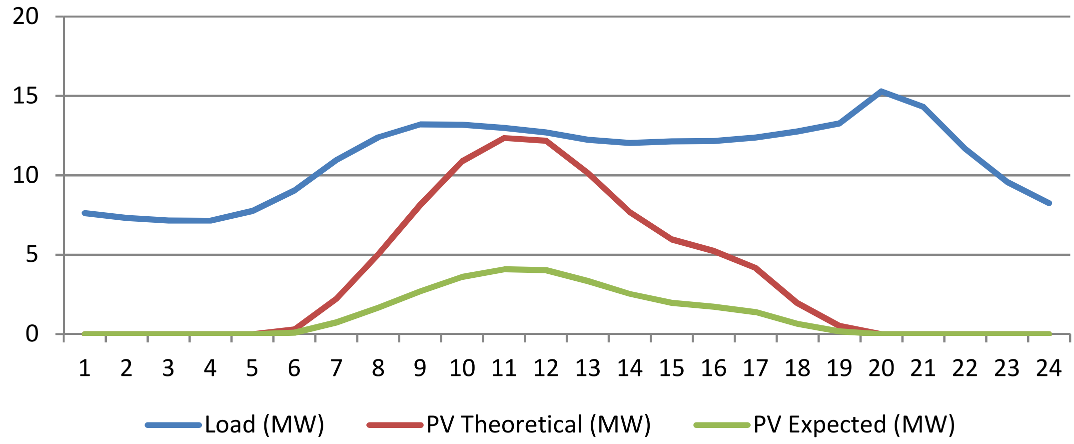


Figure 23: Balti PV Production Curves at Low Load Conditions (2 May 2016)

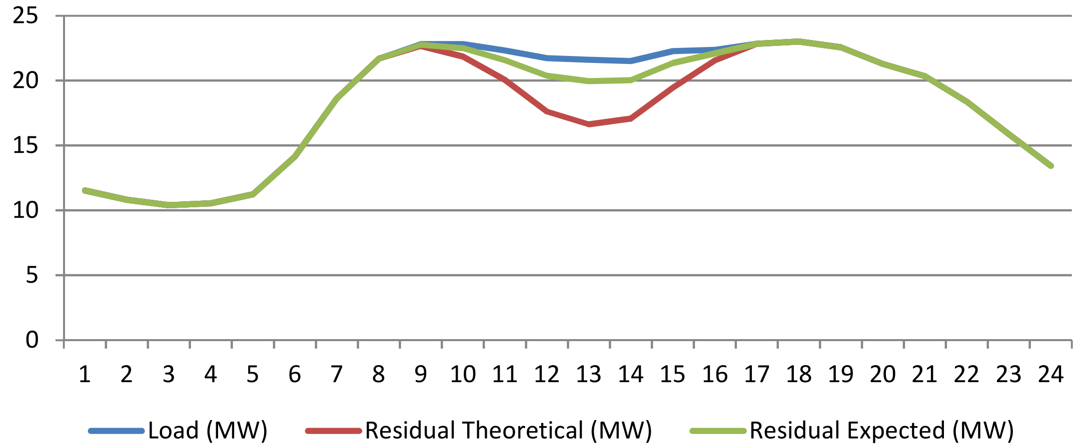


Figure 24 Balti Load and Residual Load Curves at Peak Load Conditions (16 December 2016)

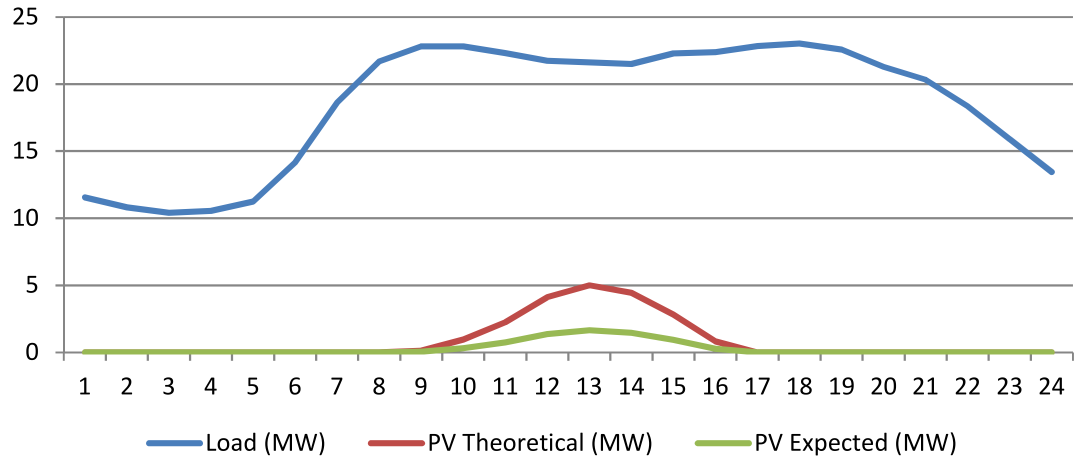


Figure 25: Balti PV Production Curves at Peak Load Conditions (16 December 2016)

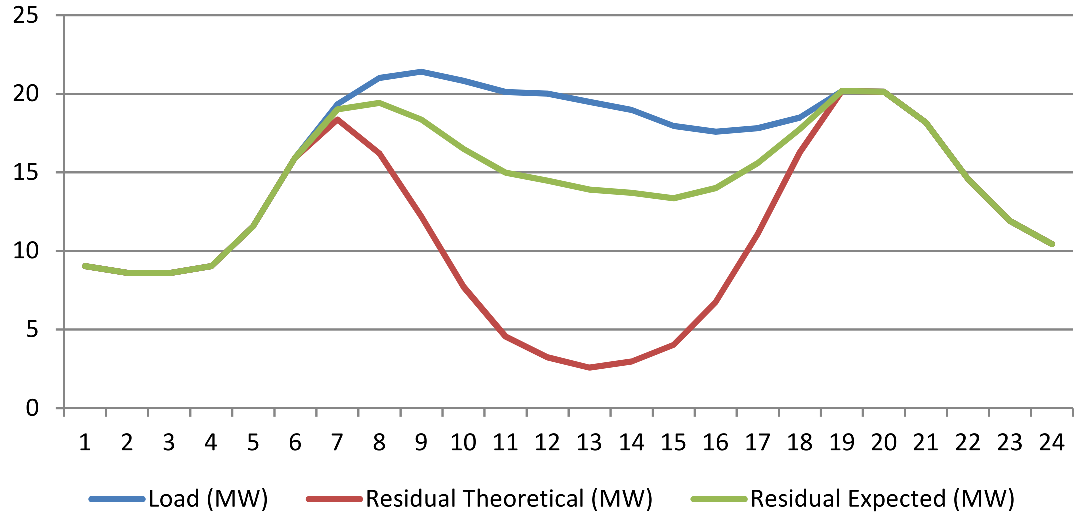


Figure 26: Balti Load and Residual Load Curves at Peak PV Output Conditions (28 March 2016)

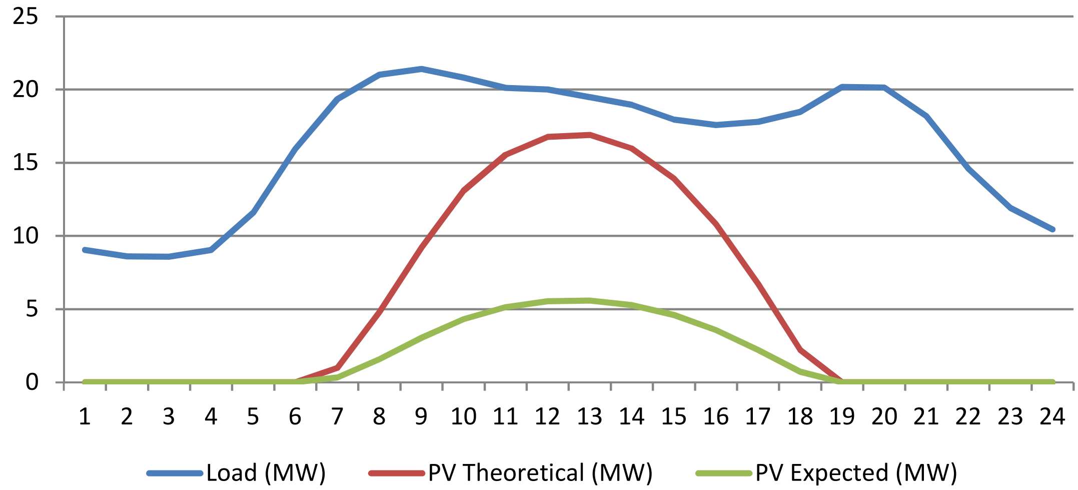


Figure 27: Balti PV Production Curves at Peak PV Output Conditions (28 March 2016)

Cahul

Cahul is the smallest city of the three and the situation observed in Balti is repeated. In this case we also have the specificity of having the maximum PV output happening in autumn (14 October) instead of spring.

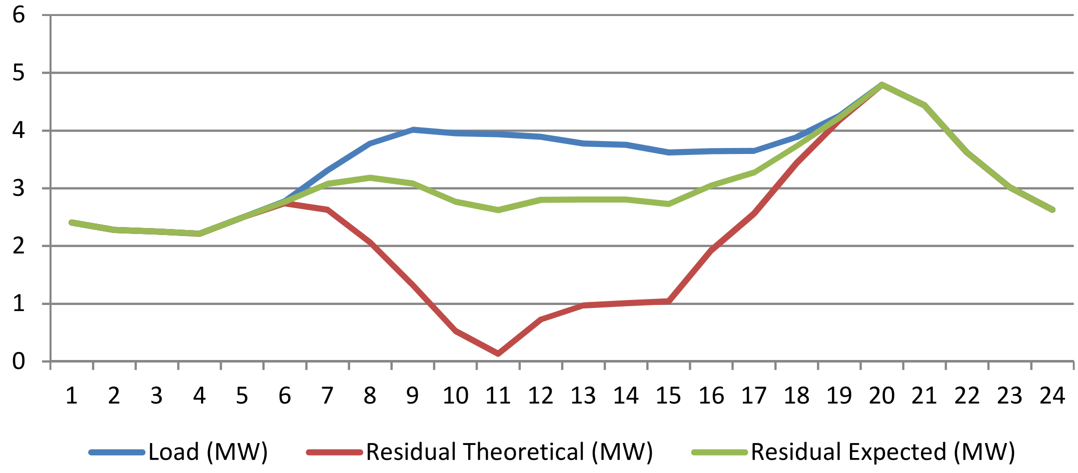


Figure 28: Cahul Load and Residual Load Curves at Low Load Conditions (2 May 2016)

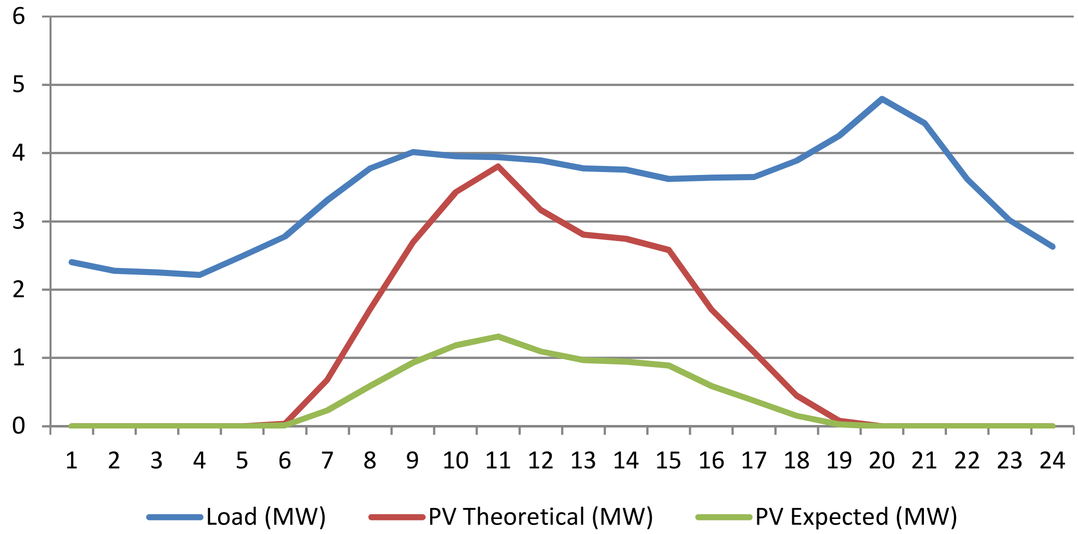


Figure 29: Cahul PV Production Curves at Low Load Conditions (2 May 2016)

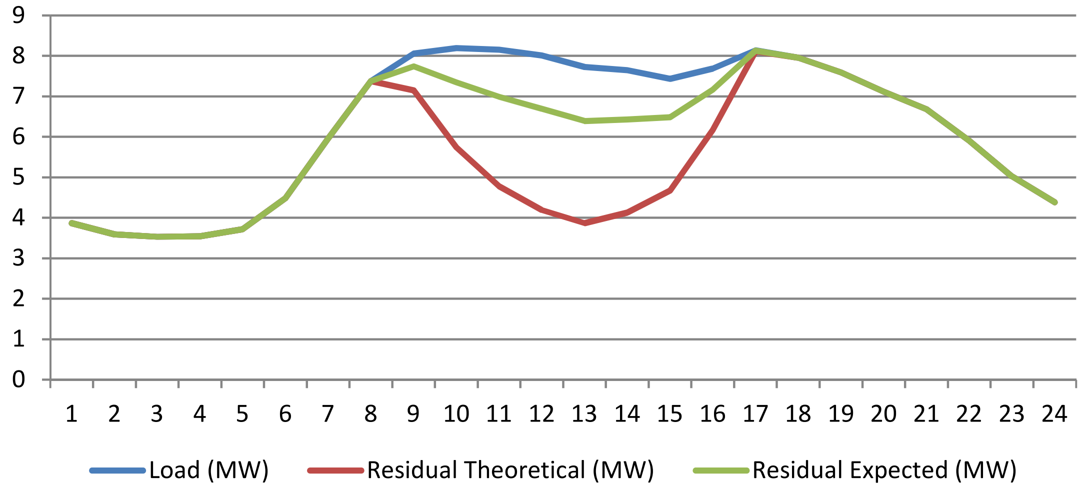


Figure 30: Cahul Load and Residual Load Curves at Peak Load Conditions (16 December 2016)

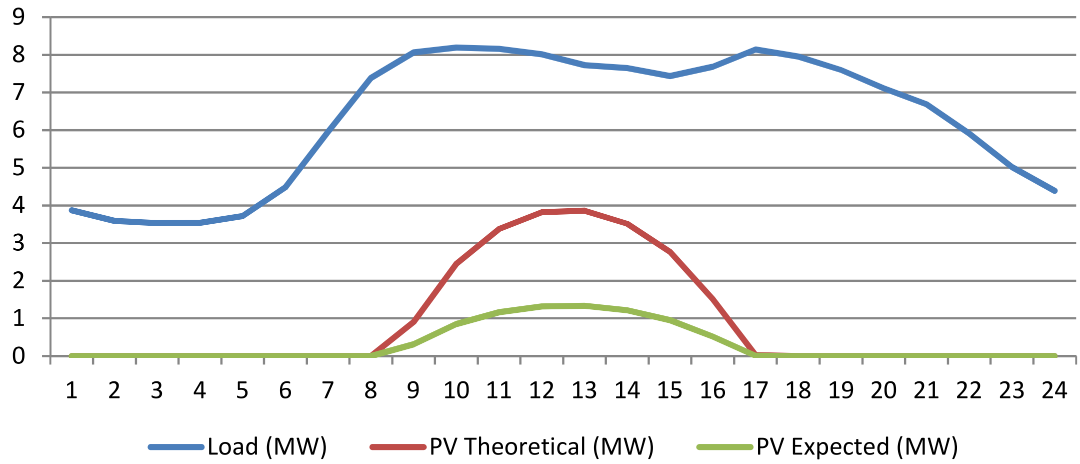


Figure 31: Cahul PV Production Curves at Peak Load Conditions (16 December 2016)

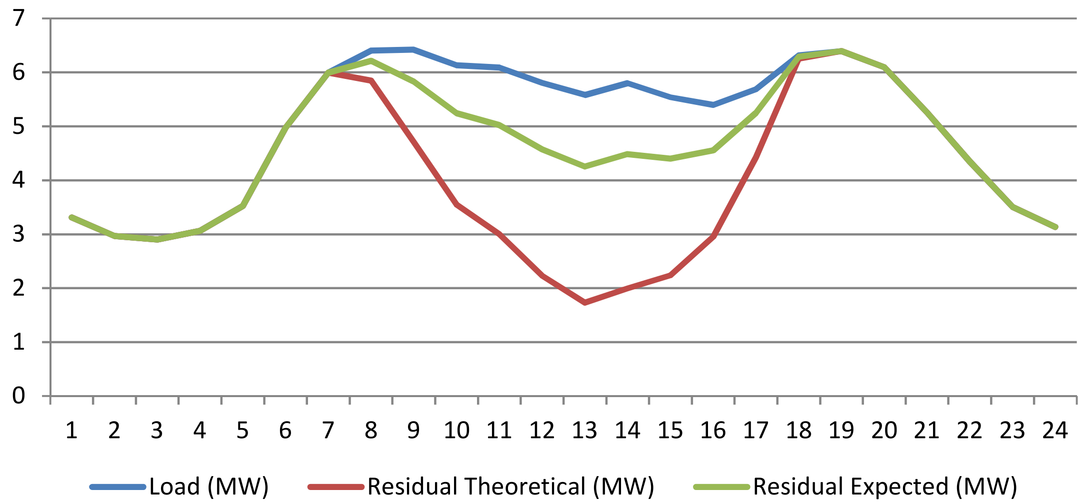


Figure 32: Cahul Load and Residual Load Curves at Peak PV Output Conditions (14 October 2016)

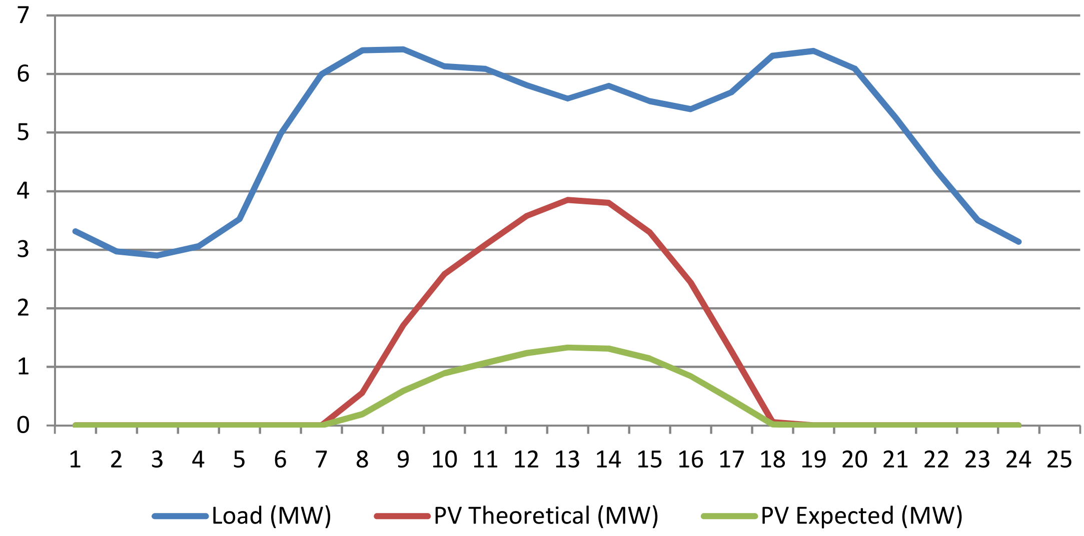


Figure 33: Cahul PV Production Curves at Peak PV Output Conditions (14 October 2016)

Concluding on the analysis at city level we can observe that the effects of introduction of building-PV are more evident compared to the system-level analysis and moreover that the size of the city does matter in this respect. The city micro-climate as well as the level of industrial (or other electricity-intensive) activity may also play a role in the relationship and coincidence of the city electricity load and PV output. The plurality in residual load curves shapes for almost the same time snapshots is a first evidence though more analysis would be required for firm conclusions to be made.

6.2.1.1 Armenia, Azerbaijan, Belarus and Ukraine

No residual load curve calculations could be performed due to the unavailability of detailed data. Conclusions however from such an analysis in all countries are expected to be similar to those extracted for Moldova.

6.3 Centralised vs de-centralised PV

We understand that so far the decentralised PV development is currently negligible in all countries compared to the current electricity generation installed capacity. Our review on published sources reveals that currently there is no formal policy guidance or rule distinguishing PV capacity additions into utility scale and distributed generation. In most cases the TSO (reasonably) expects exclusively utility-scale new PV capacity additions under the penetration margins discussed above in section 6.1. Largely this estimate is based on the so far level of interest expressed by the potential investors in solar PV technology in each country.

6.3.1 Moldova & Ukraine

In both countries transmission planning is part of the overall energy planning exercise and there is no evidence that it takes currently into account the possible development of distributed generation. The TSOs in both countries have considered the overall impact of renewables in the system but the analysis was based on utility scale additions of new RES generation. Distribution network planning is only evident by the 3-year investment programmes the distribution companies submit to the competent National Regulatory Authorities for the purposes of factoring investment cost into electricity tariffs. The situation is expected to change in this respect with the gradual implementation of the provisions of the new electricity law in both countries which transposes the Third Energy Package.

6.3.2 Armenia

The scaling up renewable energy investment plan (SREP) for Armenia which was developed with the assistance of Renewable Energy and Energy Efficiency (R2E2) in 2014 clearly distinguishes utility scale PV for which the claimed potential ranges between 830 to 1200 MW ("depending on which solar PV technology is deployed: Fixed PV, Single-Axis, Tracking PV or Concentrating PV") whereas the respective capacity figure for decentralised solar PV is 1300 MW.

6.3.3 Azerbaijan & Belarus

There is no specific target indicated by the national competent authorities that distinguishes utility scale and decentralised PV development.

6.4 Generation displacement

Given the wholesale market structure in most of the countries which comprises either a monopoly or a single buyer model –with some cases also involving a partially regulated and partially deregulated market - it is rather difficult to come up with a judgement on which part of the current generation mix would have been displaced if building-PVs would have been developed in each country. A year-round hourly dispatch simulation would be required to provide answers on which generation and imports would be displaced if building-PV would be introduced in each system.

6.4.1 Moldova

In Moldova, the merit order curve seems to massively be dominated by thermal generation which in turn comprises some limited coal-fired CHPs and a large portion of gas-fired generation by a single power plant.

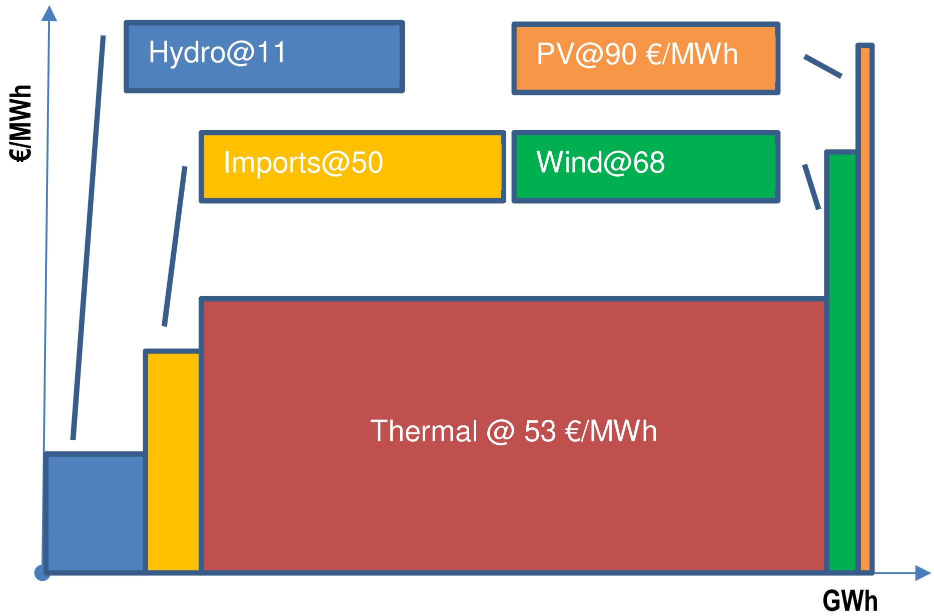


Figure 34: Simple merit order Moldova

At the current pricing system, the introduction of 261 GWh/y or 88 GWh/y would be noticeable though not particularly important since they represent the 4.7% to 1.5% of the overall annual electricity consumption in Moldova, respectively[20]. However, any possible discussion on displacement of generation caused by the introduction of building-PV capacities needs to be conditioned on the market circumstances which for the moment remain at a transition phase since neither the overall RES support scheme is elaborated to its detail nor the electricity market model is decided and implemented. Very roughly and based on information provided by Moldelectrica as well as expert estimates the following values and generation prices may be representative for the Moldovan system.

Table 47: Moldova's electricity mix and average prices

	Annual Production & Imports (GWh)	Price (€/MWh)
Wind	3.7	68
PV		92
Hydro	240	11
Thermal	2159	ca. 53
Imports	10	ca. 50

6.4.2 Ukraine

As we have learned during the elaboration of the Component 2: "Review of EaP Countries Experiences with Building PVs" report of this study the WEM (Wholesale Electricity Market) of Ukraine purchases electricity from different types of power generation at different costs. The purchasing prices for different technologies are reported in Figure 35 below.

[20] The former refer to "theoretical" PV output whereas the latter refer to the "expected" PV output as they are defined in detail in this section

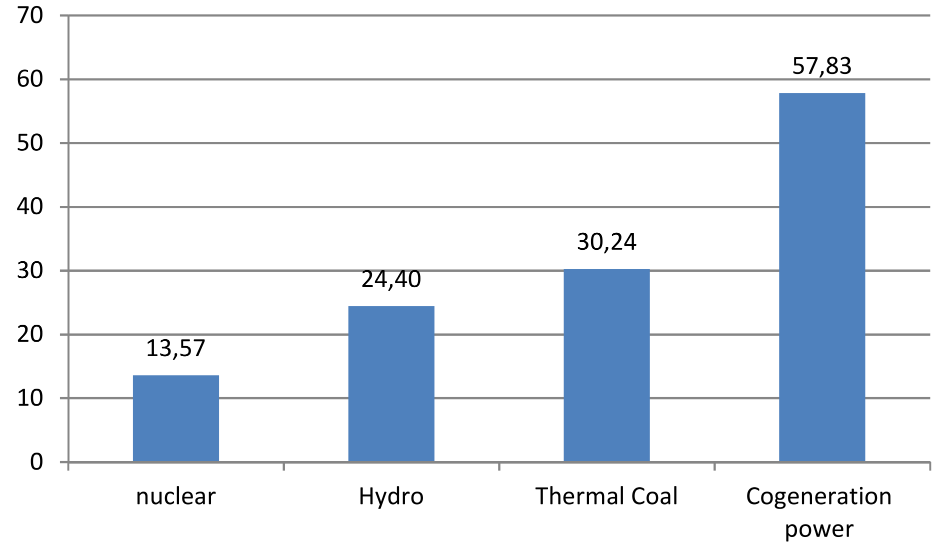


Figure 35: Electricity generation cost, €/MWh, Ukraine 2015

Combining the above price information with the generation output figures reported by Ukrenergo in their 2015 annual report[21] we could potentially derive a merit order which is representative for the Ukrainian system.

Table 48: Ukraine's electricity mix and average prices

	Annual Production (TWh)	Price (€/MWh)
Nuclear	87.63	13.57
Hydro & pump storage	6.81	24.40
Thermal (Coal)	49,39	30.24
CHP & Other thermal	12.39	57.83

6.4.3 Armenia

Generation prices are regulated in Armenia by the Public Services Regulatory Commission. PSRC in collaboration with the World Bank produced in June 2016 a video[22] explaining how electricity tariffs are calculated. The video was broadcasted by Public Television of Armenia and in was financed by the Energy Sector Management Assistance Program. Below in Figure 36 we present a screenshot indicating the average electricity purchase price by the Electricity Networks of Armenia (single buyer) as well as the respective average generation prices in AMD per kWh.

21 https://ua.energy/wp-content/uploads/2016/12/zvit_ukrenergo_2015.pdf
22 http://www.worldbank.org/en/news/video/2016/06/27/electricity-tariff-calculation-for-armenia

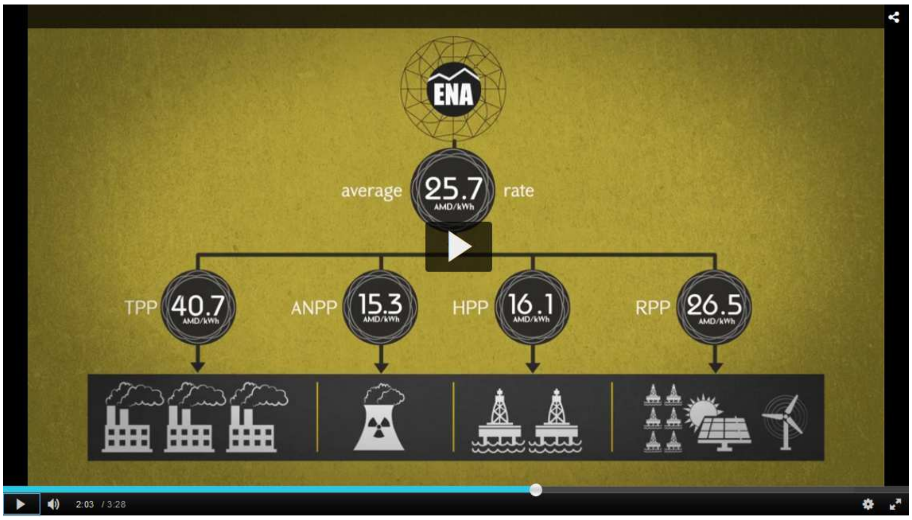


Figure 36: Regulated electricity prices in Armenia, €/kWh (2016)

Combining the above price information with the generation output figures reported by International Energy Agency in their 2015 report on the Eastern Europe, Caucasus and Central Asia region[23] we could potentially derive a merit order which is representative for the Armenia system.

Table 49: Armenia's electricity mix and average prices

	Annual Production (GWh)	Price (€/MWh)
Nuclear	2304	26.8
Hydro & pump storage	1776	28.2
RES (SHPP)	536	46.5
Thermal (Gas)	3384	71.4

6.4.4 Azerbaijan & Belarus

It is not possible to conclude on a merit order of the generation mix for both countries given the vertical organisation of their electricity markets. On the other hand, given the currently low targets and quotas for the development of solar PV a further analysis on generation displacement would not be a crucial parameter in the discussion for the development of a building-PV program.

6.5 Congestion management

One of the key benefits of the building-PVs is that they reduce the need for energy delivery from central power stations through the network to the load centres. In many cases the introduction of building-PVs in cities should lead to alleviation of any congestions (particularly if high load hours coincide with daylight!). On a planning level the above reasons along with the currently expected

[23]https://www.iea.org/publications/freepublications/publication/IDR_EasternEuropeCaucasus_2015.pdf

penetration rates do not constitute any particular driver for the development of the system with a view to alleviating congestions cause by RES injections.

6.5.1 Moldova

According to Moldelectrica there are no congestion conditions at this point in supplying the electricity to Chisinau, Balti or Cahul.

6.5.2 Ukraine

The Ukrainian TYNDP 2017-2017 in its 3.6 section[24] describes the nature of a number of structural constraints in the Ukrainian power system. Among these the insufficient western (with relevance also to Lviv), south-western region reactive reserves, limited capacity of circuits around the Zaporizhia area and capacity constraints of specific network element in the southern east-west corridor (involving Odessa) as well as the lack of transformer capacity in the central region (and in particular in Kyiv area due to the sudden recent demand increase) are explicitly mentioned. Though these structural constraints appear to be present irrespectively of the foreseeable location of RES developments in these regions it is required to be studied in a much greater detail as to what impact RES additions would entail in the regions where structural constraints are present. For example, in Kyiv the introduction of distribute generation would at least initially help in the transformer loading reduction for daylight hours in the spring to autumn period while network transfer stress on specific corridors in the south Ukraine might be aggravated during the same period.

6.5.3 Armenia, Azerbaijan, Belarus

There is no specific information on structural congestion issues in these countries. In part this is reasonable since the existing organisation of the electricity market treats congestions as an “internal” to the vertically integrated utility or single buyer problem and re-dispatch has not external financial consequences on any third party.

6.6 Infrastructure development

Network planning in the region is mostly driven by the need for enhancing reliability i.e. N-1 criterion. In respect of RES development there no dedicated network infrastructure plans yet. Likewise, we have been not able to identify any studies or projects specifically planned to accommodate (enable the integration of decentralised PV) in specific areas of the grid. Moreover, in our review we haven’t been able to identify any planned or considered investments in generation or the transmission grid that would be avoided if sufficient generation by decentralised PV was in place. On the other hand, the proposed by this study building-PV capacities, do not seem to necessitate network investments. In other words, it is not possible to valorise

6.6.1 Moldova

According to Moldelectrica, any increase in local generation would avoid the need for transmission infrastructure especially taking into the consideration the deficit of installed power in the mainland of Republic of Moldova. At this point it is considered that there is enough capacity to accommodate a reasonable amount of renewables penetration. It is estimated that at a system level the transmission grid would be able to transmit approximately 1000 MW.

[24] Page 45, https://ua.energy/wp-content/uploads/2016/12/Proekt-Planu-rozvytku-OES-Ukrayiny-na-2017-2026-roky.pdf

6.6.2 Ukraine

There is no evidence that - other than the contribution to supply/demand balance - the Ukrainian TYNDP 2017-2026 considers RES development as an important driver. Either at the order of 4.2 GW for wind and Solar PV as it was verbally communicated to as or approximately 4.4 for all RES (wind, PV, biomass) as it is reported in the Ukrainian TYNDP 2017-2026 (see Table 42 above), decarbonisation appears as a far future objective. The key drivers for the development of the Ukrainian transmission system seem to be rather the demand coverage and enhanced reliability as well as the strategic aim of integrating the system with that of ENTSO-E Continental Europe.

6.6.3 Armenia, Azerbaijan, Belarus

There is no specific information on dedicated network planning activities including those addressing specific RES development drivers in these countries. This however needs not to be misinterpreted as if the countries miss network planning as a whole. On the contrary electricity system planning is integrated (e.g. generation expansion, transmission & distribution planning). The parts of electricity system planning are usually included as part of the national energy strategy. Planning objectives are usually restrained to demand coverage, increase of delivery reliability and cross-border trading whereas the aspect of promoting competition and renewables are not currently presented as key drivers for the development of the electricity system. Another characteristic is that the proposed network projects are often influenced by the general energy policy objectives (e.g. strengthening the electricity network in order to avoid gas consumption) or by the expressed interest of international financing institutions and donors.

6.7 Balancing cost

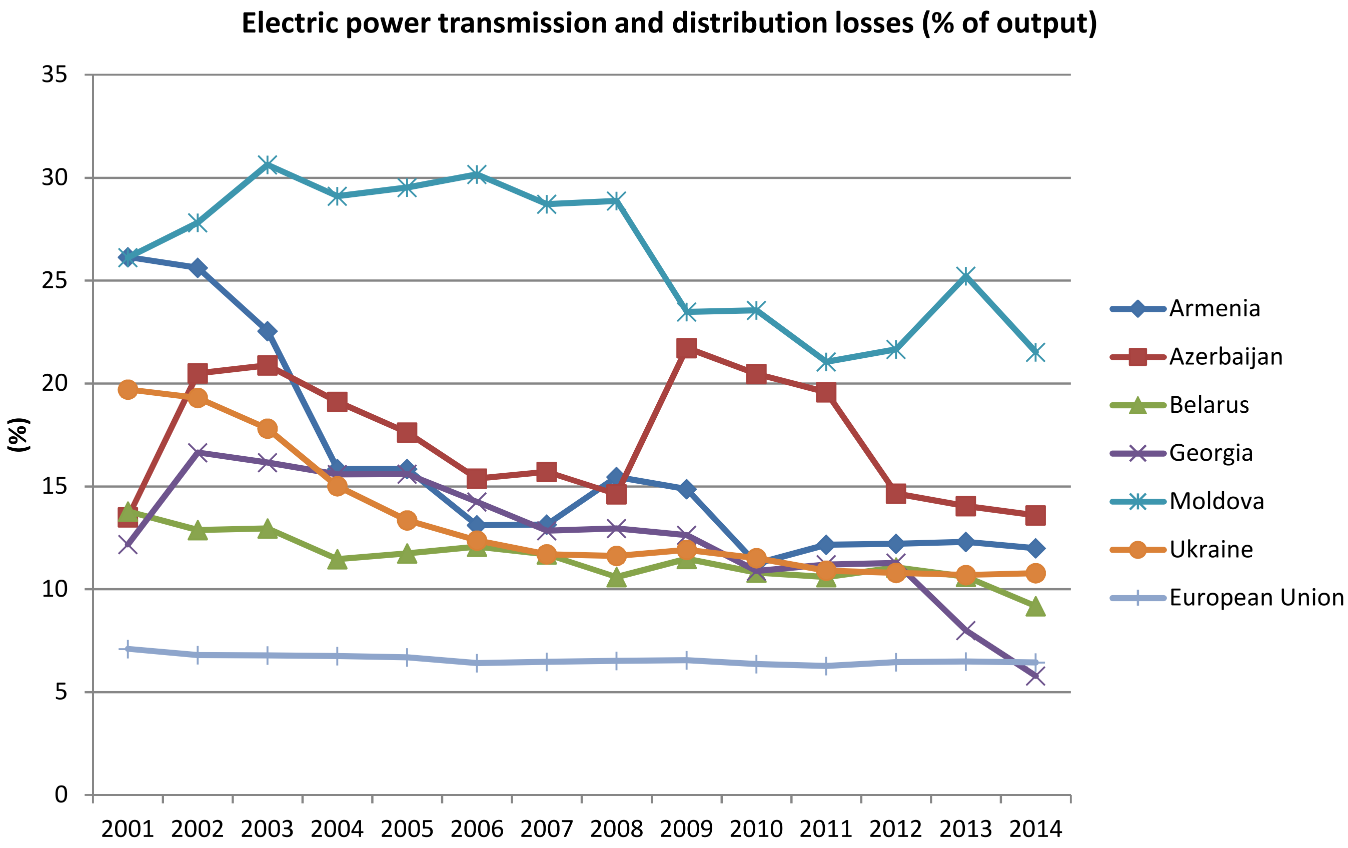
It is important to mentioned that the current balancing practices in the region deviate from those that that have emerged in most of the EU Member States and those rules implementing the balancing markets as part of the EU Target Model as it is in particular described in the Electricity Balancing Guideline (EBGL).

Therefore, at the moment it was impossible to retrieve any electricity balancing cost indicators which may have been developed the TSO based on previous operational experience (e.g. Euros/ MW of installed PV). In general, the current market balancing costs are implicitly covered through energy trading commercial agreements (either with generations or through import). There is no penalty for poor forecast and deviation from the schedule. Therefore, costs of balancing energy and reserves are neither identifiable in general nor can be attributed in any way to the presence of intermittent RES generation in the power system. It is expected that at some point a balancing mechanism would be introduced as part of the new electricity market models in each country and particularly in the Energy Community Treaty Contracting Parties which have opted for a greater harmonisation with EU acquis.

6.8 Losses

Like many other indicators discussed above in the case of losses it is also impossible to isolate the effect of intermittent RES, evaluate their impact and possibly come up with some indicative benefits or costs that may appear as the impact of developing building-PVs in Georgia. Though there is experience in the EU as it is discussed in section 2.4 of the “Review of EU Experience with Solar PV in buildings” report which relates the impact on losses with intermitted RES generation, it would be advisable that this is not taken for granted given individual network characteristics in each country. It can be anticipated however that at these low penetration rates of building-PV as they are suggested in this study impact on losses should be positive i.e. lead to a losses reduction.

It is worthwhile to be mentioned however that all Eastern Partner countries have over the past years achieved a considerable level of electricity network losses reduction by undertaking an equally substantial level of rehabilitation and extension of their transmission and distribution networks. Based on data proved by the World Bank data website, which in turn uses data series provided by the International Energy Agency[25], we have collected and present in a comparative graphical form in Figure 37 below, the annual losses for each of the Eastern Partner countries (plus the reported EU average respective figures) for the period 2001 -2014 expressed as electric power transmission and distribution losses (% of output):



Source: WB Data (using IEA Statistics © OECD/IEA 2014)

Figure 37: Evolution of T&D losses in all Eastern Partner countries (compared to the EU average)

Overall, in the absence of detailed calculations carried out by the respective network operators the losses discussion does not really weights on the decision for the development of a building-PV program in all countries. It is generally anticipated that at the penetration levels discussed even at policy target levels, electricity losses may be reduced with the introduction of RES capacities throughout the system. However, this is not easily quantifiable at the moment and it would also be extremely difficult to be isolated by the existing network rehabilitation and expansion plans in the countries. Therefore, impact on losses is not taken into account in our study and the following information on Moldova and Ukraine are provided for indicative purposes.

[25] IEA Statistics © OECD/IEA 2014 (http://www.iea.org/stats/index.asp), subject to https://www.iea.org/t&c/termsandconditions/

6.8.1 Moldova

Losses in Moldova appear to be on average comparable to those of other networks in the EU. According to Moldelectrica, in the context of the above capacities building-PV, it is reasonable to expect that the losses will decrease in the transmission grid.

Table 50: Losses (%) in the electricity transmission and distribution networks during the years 2015 & 2016

Network operator	2015	2016
SE Moldelectrica (TSO) [26]	2.66	2.69
ICS RED Union Fenosa S.A. (DSO) [27]	8.21	8,25
S.A. RED Nord (DSO)[28]	9.19	8.82
S.A. RED Nord Vest(DSO)	9.32	9.77

6.8.2 Ukraine

A breakdown of distribution losses per regional distribution company could not be retrieved during our data collection. The Association of DSOs[29] reports a cumulative 12 884,5 GWh or equivalently 9.9% the electricity injected from the transmission to the distribution networks which in turn originates from NEURCs annual report for 2016[30].

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[26] For transmission system operator according to SE Moldelectrica website: http://moldelectrica.md/ro/network/annual_report

[27] For Distribution system operators according to the Report on the activity of the National Agency for Energy Regulation in the year 2016. http://anre.md/files/raport/Raport anual de activitate_2016.pdf

[28] It is necessary to mention that at present it is the process the merging procedure of the two DSOs (S.A. RED Nord and S.A. Red Nord Vest)

[29] http://adsoeukr.org/en/info

[30] http://www.nerc.gov.ua/data/filearch/Catalog3/Richnyi_zvit_2016.pdf

7 Conclusions

The main purpose of this component of the study has been to explore potential ways for building-PV deployment in the 5 Eastern Partner Countries (Armenia, Azerbaijan, Belarus, Moldova and the Ukraine), including development of scenarios of staged deployment in the future years and analysis and cost-benefit assessment of potential policy measures to be implemented in the country to support building-PV market uptake.

Analysis undertaken in the Component 1: “Review of EU Experience with Solar PV in buildings” report of this study had suggested the implementation of specific policy support programmes tailored on building-PV deployment, to serve as a pilot to open up or, in particular in the case of Ukraine, to scale up the market and allow PV system costs to decrease and the value chain to be created, thanks to a progressive deployment, market expansion and experience.

This report has taken a step further by developing scenarios for increasing levels of building-PV penetration in the 5 Eastern Partner Countries in over the period 2018-2022 associated to different levels of governments’ commitment over building-PV deployment following a simple yet evidence-based logic: the higher the commitment, the higher the policy support required for implementation (see Section 3.2 for more details).

Deployment scenarios have been developed based on the potential PV capacity on buildings estimated in the Component 3: “Quantification of the potential of building-PVs in Georgia and the rest of the Eastern Partner countries” report of this study. The main conclusions and takeaways from end user and cost and benefit analysis of the above scenarios include the following:

- The end user analysis has indicated that in all five countries, under the current RES and specifically PV policy support framework, financial attractiveness of building-PV investments is low due to the adoption of NM based on the existing relatively low end-user electricity prices. Therefore, with the exception of Moldova, where the evolution of electricity end user prices may make building-PV feasible in the next 3 to 4 years, we do not foresee a substantial building PV capacity to be deployed.
- Additional support would be needed to make building-PV systems financially attractive and hence attractive for the end user, always keeping in mind the stage of development at which the electricity markets of those countries are. The support policies that seemed most suitable and were analysed are: capital grants and FiT schemes.
- For Armenia we estimated a deployment of building-PV capacity ranging between 92-185 MW under medium and high scenarios, which could be supported either by a 5 years capital grant programme (in conjunction with net metering) with a total cost ranging between € 36 million and € 96 million; or a FiT scheme of 5 years with a total cost over the lifetime of the programme of ranging between € 192 million and € 471 million.
- For Moldova we estimated a deployment of building-PV capacity ranging between 7-14 MW under medium and high scenarios, which could be supported either by a 5 years capital grant programme (in conjunction with net metering) with a total cost ranging between € 646,000 and € 4 million; or a FiT scheme of 5 years with a total cost over the lifetime of the programme of ranging between € 12 million and € 33 million.
- For Ukraine we estimated a deployment of building-PV capacity ranging between 281-561 MW under medium and high scenarios, which could be supported either by a 5 years capital grant programme (in conjunction with net metering) with a total cost ranging between € 206 million and € 456 million; or a FiT scheme of 5 years with a total cost over the lifetime of the programme of ranging between € 894 million and € 2 billion.

- For Belarus we estimated a small deployment programme of 25MW per year over 5 years, supported by a FiT scheme whose total cost over the lifetime would be about € 43 million.
- Similarly, for Azerbaijan we considered a 1000 rooftop programme leading to a total installed capacity of 5MW over 5 years, for a total FiT scheme cost of the lifetime of the programme of about € 10 million.
- In Armenia, Moldova and Ukraine, where capital grants (in conjunction with net metering) and FiT scheme are assessed as alternative policy support solutions to deliver the same level of building-PV deployment, the results show an higher total policy cost over the lifetime of the programme for FiT scheme when compared with capital grant (despite the annual cost is quite comparable, in particular for Armenia and Ukraine).
- If FiT schemes in the different countries had to be financed by means of a RES levy, the overall potential economic impact on households' electricity consumers is estimated to be relatively low. However, potential adverse social redistribution effects must be taken in due care while designing the policy instrument (see also below).
- The calculated FiT policy cost (i.e. FIT scheme based on generation tariff) should be intended as the highest policy cost, whereas alternative designs of FiT combined with self-consumption scheme may result in a lower policy cost.
- The deployment of building-PV capacity in in the 5 Eastern Partner Countries would bring environmental and social benefits which have been quantified in terms of CO2 emissions achieved and jobs created.

A series of objective reasons have prevented us from developing definite and quantitative assessments on various costs and benefits of the potential impact of building-PV integration to the local distribution grids. However, a qualitative discussion over possible impacts has been presented. Moreover, experience with distributed generation development has shown that it is actually a multifaceted issue involving a number of technical and regulatory decisions, which also in their turn imply decision-making interdependencies. Most importantly, the policy decision of developing distributed generation usually relates with the overall ambition for a decarbonisation of the electricity system, which is translated into a high level of RES penetration. Conversely, where certain conditions are not considered to be met (e.g. decarbonisation is not yet a strong energy policy driver and/or energy security is vulnerable and/or the level of grid preparedness is low), RES penetration often takes small and cautious steps - and should the investment climate allow to do so - they are usually realised at transmission network level. As it was also discussed in section 2.4 of the Component 1: “Review of EU Experience with Solar PV in buildings” report, the level of understanding on the overall impacts of RES integration relates with the penetration rate and most importantly in the initial stages of development. This is often understood as an isolated issue relating only to the determination of hosting capacity, whereas operational and infrastructure impacts are usually neglected. Experience has however shown that this should be treated with care.

Therefore, the first decision which relates with the policy decision of developing distributed generation is whether the relevant grid impact shall be treated isolated (i.e. only for the distribution network). In some countries that practice involved an isolated approach which in effect had to do only with the assessment of hosting capacity. However, with the empowerment of electricity end-users and the development of competition in the retail segment of the electricity market such an approach may reveal short-sighted. It is therefore generally proposed that the Eastern Partner Countries benefit from the experience of certain EU member states and tackle the issue in its full extent and with due appreciation of the various conditions and parameters associated with an increased RES penetration on both the transmission and distribution level.

Secondly, and if in particular the decision is to treat the subject collectively in respect of the impact to the transmission and distribution network, a TSO-DSO cooperation is imperative to be established. There is currently a growing debate in Europe on how TSO-DSO cooperation may establish common working rules for on distributed flexibility, encompassing the TSO-DSO interface, data management, network fees and retail market integration of storage, empowerment and privacy rules for the customer, self-consumption and managing interactions between suppliers and independent aggregators. Soon as the fundamentals are established, TSOs and DSOs may extend their cooperation further in order investigate further integrated solutions for balancing and congestion management, at both TSO and DSO levels.

Evidently different reasons have prevented us to develop definite and quantitative assessments on various costs and benefits comprising the impact of building-PV integration to the local distribution grids.

Given that a study on intermittency analysis - including at distribution level - is currently not available in the Eastern Partner countries it would be advisable that the aspects that were briefly touched upon in our review in this section are further investigated at national level. It can therefore be proposed that the following aspects are taken into account in a possible follow-up study ideally with the participation of both the TSO and the DSOs in the country:

- Hosting capacity: The assessment needs to be initiated at distribution level taking into consideration the effects of voltage rise on the feeders on which PVs are connected, cable loading and transformer capacity. Both statistical and deterministic methodologies may be engaged in the assessment. Results at city level need to be checked at transmission level thereby checking the network element operational limits via load flow and short-circuit studies.

- Market impact/generation displacement: This assessment needs to perform though an hourly dispatch simulation taking into account must-runs, dynamic characteristics of the other generators in the system as well as the load forecast. Resulting scenarios should then be checked for their validity by load flow simulations

- Infrastructure development: relates with both DSO and TSO assessment of either avoided network cost (i.e. if valid generation scenarios are able to postpone or even cancel required network expansion/reinforcement or rehabilitation) or in the opposite dedicated network projects required for the timely connection of future RES projects

- Balancing cost: Though balancing cost may be unavoidable it is always for the benefit of the optimisation of power system operations that the TSO is aware of the reserve needs which emerge with the increased penetration of RES. This assessment is useful in order to establish that imbalances caused by a market party are taken care of by the same party in a fair and transparent manner. In addition, such an assessment can in addition help in the determination and improvement of weather forecasting services required for scheduling. Last but not least such a study may help in decisions to be made in the wholesale market design such as the operation and determination of Programme Time Units (PTU) in the intra-day market.

- Losses: require a harmonically arranged TSO-DSO cooperation particularly if the supply/demand conditions in the network are such that reverse power flows from distribution to transmission become evident. Though this usually happens in cases where large distributed generation penetration margins have emerged (for instance in Denmark or some regions of Portugal), it may as well be part of the assessment in the Eastern Partner countries in times where the seasonal PV output reach its maximum while the demand remains at relatively low levels.

Particularly referring to the economic impact of losses forecasting, this can be of a particular value for those network operators where losses are procured at a centralised level since proper planning should prevent losses forecasting errors.

7.1 Recommendations

Eventually, this study, similarly to Component 4:"Programme development for building-PVs based on a Cost-Benefit Analysis: Georgia" report of this study, had the task to carry out a Cost Benefit Analysis, so as to determine the feasibility and viability for promoting building-PVs in Armenia, Azerbaijan, Belarus, Moldova and the Ukraine. From the study's results emerges clearly, that building-PVs can play a significant, although not dominant, role in the energy balances of the five countries. The market segments were determined and the useful potential calculated. Gaining, however these markets is not a self-initiated development as the example of the most advanced PV markets shows. Targeted policies are needed with careful quantification of their costs and benefits so as to have a solid validation. Furthermore, a similarly careful determination of the stakeholders' role is needed so as to allocate costs and benefits in an effective, yet also socially bearable way.

Taking into account the key issues common to all five Eastern Partner Countries addressed in this Study, the following actions can be proposed for an effective promotion of building-PV:

- Organisational innovation[31] is key for the design and implementation of an appropriate programme for the development of building-PVs. Given that the proposed programme is proposed to be led by a national public institution, organisational innovation shall be regarded as the process of ensuring project aggregation and financing solutions minimising transaction costs and engaging the (international and/or private finance community. It would also include the removal of legal, administrative and other market barriers for bringing the specific investment pipeline to a financial close (possibly following the proposed staged development if they are in agreement the plans of the partner financing institutions). This calls for regulatory and administrative actions, which can only be undertaken by national competent authorities. The Ministries responsible for energy and the national RES/EE agencies where relevant are the key stakeholders, although it obviously also will have to act as a focal point for other authorities – both at central government and local level - as well.

- Access to improved financing is key for the development of building-PV programmes. In our view engaging with the IFIs is crucial with the view to increase financing for instance by exploring the possibility of or the extent to which aggregation and standardisation of financeable solutions is feasible. In this respect the present report can act as the introductory study on which the IFIs may base their own assessments and eventually come up with their own specific solutions.

- When it comes to the specific polity tools required, a Feed-in-Tariff appears to be the more appropriate instrument, since it would reduce investment risks and provide the necessary basis for the engagement of financing institutions.

- FiT scheme could be financed by means of a RES levy, thereby the cost would be charged and passed on to the final electricity consumers. However, care should be taken in designing and

[31] http://ec.europa.eu/eurostat/statistics-explained/index.php/Glossary:Organisational_innovation

implementing the scheme to avoid excessive burden on end-users and adverse social redistribution effects (possible measures are proposed, see also discussion in Section 4.2.2 and 4.3 of Component 4:“Programme development for building-PVs based on a Cost-Benefit Analysis: Georgia” report of this study).

- The implementation of capital grant scheme (or alternatively soft loan scheme) in conjunction with FiT scheme might help final end users to overcome access to capital barrier, thus facilitating investments and guaranteeing higher levels of building-PV deployment.

- Capital grant and soft loan schemes could be financed through specific International/Multilateral Financing Institutions’ programmes, due to both their relatively small total cost and the fact that their cost burden is limited to a few years, compared to FiT which requires longer term commitment.

- It would also be appropriate to promote building-PV also via other policy mechanism such as obligation to install building-PV in new building development in percentage of expected building final electricity consumption. This will scale up building PV market on the basis of an obligation and not an incentive thus reducing long term policy cost.

- The integration of building-PVs in the electrical systems of the countries considered is a further issue where further work has to be carried out, as there are significant problems that have to be tackled, in order to maximise the benefits of distributed generation and reduce the impact of adding non-dispatchable generation in the urban environment, with its highly stochastic demand. There are structural and organisational issues, like the cooperation of the TSOs, the DSOs and the market actors, that should be addressed – and this by no means a discussion limited to the Eastern Partnership Countries, as it an ongoing one also in many EU countries.

- Furthermore, as it emerged from the discussion of section 6, more explicit, quantitative assessments on the various costs and benefits comprising the impact of building-PV integration to the local distribution grids are also needed, as no studies on the intermittency analysis are available for the Eastern Partner countries. Hence, the aspects of hosting capacity on a national and city’s level should be considered, along with the generation displacement on an hourly level, by means of dispatch simulation. Those aspects have eventually to be linked to the costs of balancing the transmission systems and planning the development of infrastructure, to be able to cover future RES projects, admittedly building-PVs being not the major cause of concern.