WORLEY FOR USAID

ASSESSMENT OF LOCAL POWER
GENERATION OPTIONS IN MOLDOVA,

Conceptualization Study Report CLIN 01

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Appendices

LIST OF EXHIBITS

ACRONYM LIST

ACB	Ananiev-Cernauti-Bogorodceni [pipeline]
ACC	Air Cooled Condenser
AGRI	Azerbaijan Georgia Romania Interconnector
ANRE	National Agency for Energy Regulation of the Republic of Moldova
ASHRAE	The American Society of Heating, Refrigerating and Air-Conditioning Engineers
ATI	Ananiev–Tiraspol–Ismail [pipeline]
APA-CANAL	Moldavian provider of water and sewage services
Bcm	billions cubic meters
bcma	billions cubic meters per year
Bn.	Billion (s)
CAGR	Compound Annual Growth Rate
CAPEX	Capital Expenditures
CCGT	Combined Cycle Gas Turbine unit
CET	Centrala Electrică Cu Termoficare
CESEC	Central and South-Eastern European Gas Connectivity
CERS	Centrala Electrica Regionala de Stat (Romanian); the State Regional Power Plant
CHE	Centrala Hidroelectrica (Romanian); Hydroelectric Plant
CHP	COMBINED HEAT & POWER GENERATION
CS	Gas Compressor Station
CT	Centrală termică
CTG	Gas Turbine Generator
CTP	Centralized Thermal Control Point
DC	Direct Current
DSO	Distribution System Operation
DH	District Heating
DH NETWORK	District Heating Transmission System
DHW	District Hot Water Supply / Service
DSM	Demand Side Management
EBRD	European Bank for Reconstruction and Development
EC	European Commission
EEC	European Economic Community
EIB	European Investment Bank

ACRONYM LIST

EMR	Electricity Market Rules
EnCS	European Network for Cybersecurity
ENTSO-E	European Network of Transmission System Operators for Electricity (Eu)
ENTSO-G	European Network of Transmission System Operators for Gas
EPC	Engineer Procure Construct
EU	European Union
EUR	Euro
FEE	Furnizare Energie Electrica (Romanian); Electricity supply
FPSO	Floating Production Storage and Offloading Unit
FSO	Floating Storage and Offloading
FSRU	Floating Storage Regasification Unit
Gcal	Giga-calorie
GDP	Gross Domestic Product
GRS	Gas Distribution/Regulation Station
GW	Gigawatt
GWh	Gigawatt hours
HA	Hectare
HDD	Heat Degree Days
HFO	Heavy Fuel Oil
HOB	Heat Only Boiler
HP	High Pressure
HPP	Hydro Power Plant
HRSG	Heat Recovery Steam Generator
HT	High Temperature
HV	High Voltage
HW	Hot Water
IEA	International Energy Agency
INGS	Independent Natural Gas System
IUC	Iasi-Ungheni-Chisinau [pipeline]
IP	Intermediate Pressure
IRR	Internal Rate of Return
ISO	International Standards Organization

ACRONYM LIST

ITP	Individual Thermal Control Point
KWh	Kilowatt hour
Lei or Leu	The Moldavian national currency (plural or singular)
LCOE	Levelized Cost of Electricity
LCOH	Levelized Cost of Heat
LHV	Lower Heating Value
LNG	Liquified Natural Gas
LPP	Low Pressure Part
MADRM	Ministry of Agriculture, Regional Development and Environment
MGRES	Moldavskaya Power Generating station
Mcm	millions cubic meters
mcma	millions cubic meters per year
MD	Moldova
MDL	Moldovan Leu
MEI	Ministry of Economy and Infrastructure Regulation of the Republic of Moldova
mi.	Mile (s)
Mil.	Million (s)
MSL	Mean Sea Level
MW	Megawatt
MWh	Megawatt hours
NA	Not Applicable, Not Available
NBSRM	National Bureau of Statistics of the Republic of Moldova
n.d.	No data
NG	Natural gas
NOx	Nitrogen Oxides
NPV	Net Present Value
NTS	National Gas Transmission System
O&M	Operation & Maintenance
OC	Odesa-Chisinau
OEM	Original Equipment Manufacturer
OPEX	Operating Expenditures
PowerSAP	Power Sector Action Plan

ACRONYM LIST

PP	Purchased Power
PPP	Public Private Partnership
RH	Relative Humidity
RI	Razdelinaia–Ismail [pipeline]
RICE	Reciprocating Internal Combustion Engine
RED	Rețea Electrică de Distribuție (Romanian); Power Distribution Network
RES	Renewable Energy Sources
RoM	Republic of Moldova
S.A.	Societate pe Acțiuni (Romanian); shareholding Company
SCR	Selective Catalytic Reduction
SPG	Moldovagas Gas hub
SPH	Space Heating
S.R.L.	Societate cu Răspundere Limitată (Romanian); a designated equivalent to Limited Liability Company
STG	Steam Turbine Generator
Sq.	Square
SCG	Southern Gas Corridor
SCP	South Caucasus Pipeline
SCPX	South Caucasus Pipeline Expansion
SD1	Shah Deniz natural gas-condensate field
SDKRI	Sebelinka–Dnepropetrovsk–Krivoi Rog–Ismail [pipeline]
Sm3	Standard cubic meters (m3)
SRV	LNG storage, regasification vessel
SS EX	High Voltage Substation existing
SY EX	High Voltage Switchyard existing
TANAP	Trans-Anatolian Natural Gas Pipeline
TAP	Trans Adriatic Pipeline
Ths.	Thousand
Toe	Tons of oil equivalent
TO 3	Tiraspol-Odesa [pipeline]
TPP	Thermal Power Plant
TSO	Transmission System Operator

ACRONYM LIST

UA	Ukraine
UN	United Nations
USD	United States Dollar
VAT	Value Added Tax
WB	World Bank
WHR	Waste Heat Recovery

1 EXECUTIVE SUMMARY

1.1 STUDY OBJECTIVE

This study provides a conceptual assessment of the technical, regulatory, legal and economic feasibility of investment into a new state of the art power and heat generating assets in Moldova. The evaluated new generating capacities include heat sources for the Chisinau District Heating system and electric power generating units intended for balancing the Moldovan power grid.

1.2 STUDY SCOPE AND APPROACH

In order to determine the feasibility of investment into local power generation and more reliable heat supply to urban areas, an assessment of all aspects of such undertaking was performed, including electricity and heat load, capacity needs, impact on the national grid operation, the need for network related investment in line with the long term network development plans, fuel availability, applicable technology, legal and regulatory conditions, social and environmental consideration, investment sequencing for new and existing capacity and its size, cost and benefit analysis and potential ownership and financing structure. The approach taken by Worley during the implementation of the scope of work considered six tasks fulfilled in the following way.

Task 1:	Assessment of existing CHPs and related DH facilities
Task 2:	Heat and Electricity Demand and Supply
Task 3:	Gas and Water Supply
Task 4:	Land and Structural Issues
Task 5:	Legal and Regulatory Consideration
Task 6:	Technology Options

Worley efforts were closely coordinated with the USAID, the Government of Moldova and other stakeholders, e.g. ÎS Moldelectrica, SA Termoelectrica, SA Moldovagaz, etc. and their valuable input was considered during the development of this study.

A Data Request package was prepared by the Worley Team to organize the effort of information gathering for the analysis of options. The formal Data Request containing requests for all information anticipated from Moldavian sources was transmitted to the project stakeholders in Moldova prior to the Kickoff meeting. An in-country kickoff meeting and meetings with all the project stakeholders in Moldova were conducted to discuss the required information. The Worley Team visited the CET-1, CET-2 and CET Nord sites.

Drafts of the each of the task sections were submitted for review by the USAID and Moldovan stakeholders. Their comments have been incorporated into this report.

1.3 STUDY FINDINGS

1.3.1 TASK 1 - ASSESSMENT OF EXSITING CHPS AND RELATED DH FACILITIES

This section provides the results of a high-level assessment of the existing CET-1, CET-2, CT Vest, CT Sud, and CT East plants, including an assessment for the district heating related equipment located within plant boundaries. Based on the data obtained during execution of the work, several scenarios have been developed that summarize:

- minimum investment necessary for continuous operation till the new capacity is commissioned and
- necessary investment to prolong/expand the operation of CHP also to work in parallel with the new generating capacity.

REMAINING SERVICE LIFE FOR CET-1, CET-2 CHP UNITS

In the power industry, typical practice is to periodically perform comprehensive condition assessments to determine equipment suitability for extended service and to establish duration of remaining service life of major equipment. Typical scope of such assessments involves destructive and nondestructive instrument aided inspections and laboratory analysis. Since the condition assessment reports for the CET-1 and CET-2 major equipment were not provided to the project, Worley employed methodology based on statistical analysis of the expected reliable service life demonstrated by equipment of similar design and materials of construction, subjected to similar operating conditions, metallurgy control and maintenance. This stage of power equipment life is defined as Fleet Service Life. The analysis is based on the reported data for the power plants of the CET-1 and CET-2 vintage that utilize the same standardized models of major equipment (such as boilers, steam turbines, generators, transformers, etc.), and the same overall plant design and configuration. Based on the reported data, the following remaining useful service life can be conservatively assumed for the CHPs major equipment:

- CET-2 Units 2, and 3 turbines have not reached their Fleet Service life of 220,000 h. Unit 2 turbine has approximately 12 thousand hours left before it would reach its Fleet Service life, Unit 3 has approximately 19 thousand hours left before it would reach its Fleet Service life. Unit 1 has reached its Fleet Service life, but it is scheduled for a major overhaul and license extension in 2019.
- Specific Service life for CET-2 Units 1, 2, 3 turbines is expected to be extended to 300,000 h, or additional 80,000 h beyond Fleet Service life limit. However, additional maintenance costs related to metallurgy assessments, maintenance and repairs are expected during the Specific Service life period.
- CET-2 Units 1, 2, 3 boilers have approximately 80,000 h of operation left before reaching their Fleet Service life limit.
- CET-2 Units 1, 2, 3 high pressure and temperature steam pipelines have approximately 50,000 h of operation left before reaching their Fleet Service life limit.
- CET-1 operating boilers B1 through B-4 have approximately 50,000 h of operation left before reaching their Fleet Service life limit.
- CET-1 operating steam turbines TG-1 and TG-2 have approximately 150,000 h of operation left before reaching their Fleet Service life limit.

At the pace of recent years of operation, given their low capacity factor (year 2018, capacity factor ~ 0.5), the CET-2 Units 2 and 3 can likely be in operation for approximately at least another 10 years before exceeding their Fleet Service life and start requiring additional maintenance costs related to metallurgy assessments, maintenance and repairs expected during the Specific Service life period. Unit 1 should also be able to continue operation for approximately 10 years once its overhaul is completed and it is successfully re-licensed.

The same could be concluded about the CET-1 units that in recent years were in operation for approximately 4000-4500 hours per year and should be capable of operating for another 10 years up to the end of their respective Fleet Service Resource Life.

REMAINING SERVICE LIFE OF HWB

The operating heat only boilers B-2 and B-3 located at the CET-2 site have accumulated 23,729 and 20,366 lifetime operating hours respectively. These boilers are operated during the peak heat demand periods at less than 1500 hours per year on average and should have approximately at least 150,000 h of useful operating life left before reaching their Fleet Service life limit. Given their low capacity factor, boilers B-2 and B-3 can likely be in operation for at least another 25-35 years before exceeding their Fleet Service life and start requiring additional maintenance costs.

The lifetime operating hours for the operating CT-Vest heat-only boilers B-1, B-2, B-4, B-5 and B-6 have been estimated to range from approximately 5,000 to approximately 65,000. These boilers are operated during the heating season on average at approximately 1600 hours per year and should have approximately at least 100,000 - 150,000 h of useful operating life left before reaching their Fleet Service life limit. The CT-Vest boilers B-1, B-2, B-4, B-5 and B-6 can likely be in operation for at least another 25-30 years before exceeding their Fleet Service life and start requiring additional maintenance costs.

The operating heat only boilers B-2, B-3, B-4 and B-7 located at the CT-Sud site accumulated lifetime operating hours ranging from approximately 10,000 to 50,000. These boilers are operated during the heating season on average at approximately 3500 hours per year and should have approximately at least 100,000 - 150,000 h of useful operating life left before reaching their Fleet Service life limit. The CT-Sud boilers B-2, B-3, B-4 and B-7 can likely be in operation for at least another 25-30 years before exceeding their Fleet Service life and start requiring additional maintenance costs.

INVESTMENTS TO EXTEND CET-1 AND CET-2 CHP UNITS OPERATION

All the options for the new heat and power generation projects in Moldova in Section 8 of this report are proposed to replace the existing CHP capacities in Moldova. Some of the proposed options are configured to utilize the existing heat only boilers at the CET-2, and CT-Vest and CT-Sud sites. It is estimated that it would take approximately eight to ten years to develop, design, built and commissioned the new heat and power generation plants in Moldova

Under the considered options, the existing CET-1 and CET-2 CHP units are expected to be shut down once the new heat and power generating units are commissioned. However, depending upon the ultimately selected option the existing heat only boilers on CET-2, CT- Vest and CT-Sud may have to continue operation alongside with the new heat and power generating capacities. The new CHP capacities are expected to operate as base loaded, and the heat only boilers as peaking units, which should reduce their annual operating hours as compared to their historical operation.

It is reasonable to assume that the remaining lifetime and respective rehabilitation projects of CET-2 Units 1, 2 and 3 that are already planned and under way, should ensure operation of the CET-2 plant for approximately next 10 years.

CET-1 boilers and steam turbines at their current annual operating hours have sufficient resource life left for about 10 years before reaching their respective Fleet Service Resource Life. However, given the age and the vintage of the CET-1 equipment, it is judged that additional O&M expenditures related to the major overhauls of some of the equipment are likely to occur.

Indicative costs in Exhibit 1 to continue operation of the CET-1 and CET-2 plants for the next 10 years are assessed based on Worley in-house data and presented in 2019 USD.

Exhibit 1: Investments to continue operation

Plant	Costs,1000 x USD
CET-1	10,000
CET-2	30,000
Heat only boilers	5,000

The costs include major overhauls of the CET-1 and CET-2 CHP units through 2030, and an allowance for the additional O&M projects for CET-2, CT-Vest and CT Sud heat only boilers that are expected to operate for 10-15 years after the new CHP units are commissioned.

1.3.2 TASK 2 - HEAT AND ELECTRICITY DEMAND AND SUPPLY

This section presents historical and current Chisinau District Heating system heat load covered by the existing CHPs and local boilers supplying heat to the common DH network. It also presents analysis and results of the heat load forecast and the heat Load Duration Curve (LDC) that take into account the impact of the potential change of the customer base, energy efficiency improvement in the DH system.

For the electrical load assessment, this section provides historical and current electricity demand of Moldova by sectors, load characteristic, seasonal and hourly profiles, base and peak loads. A load forecast is developed, factoring the impact of consumer base changes, energy efficiency impact and the relevant conditions.

On the supply side, information on power imports, and power generation by all sources, their availability, planned and unplanned outages based on historical data also considering the near-term plans to implement new power supply sources, including an asynchronous connection with the ENTSO-E system has been gathered and evaluated. This provides information on current and anticipated demand and supply situation in the energy sector and identifies the gaps between the supply and demand.

HEAT LOAD FORECAST AND LOAD DURATION CURVE

District heating demand can be characterized by the peak heat load and the annual heat production. The peak demand (Gcal/h) is important for the sizing of the district heating sources and the supply network system. Annual district heating production (Gcal/y) determines the heat revenues and the fuel consumption requirement.

DH system heat production forecast has been performed based on the three-year Chisinau DH operation data presented in Exhibit 81, Exhibit 82, and Exhibit 83. The assumed future changes in customer base, DSM measures and reductions in DH heat losses are presented in Exhibit 87.

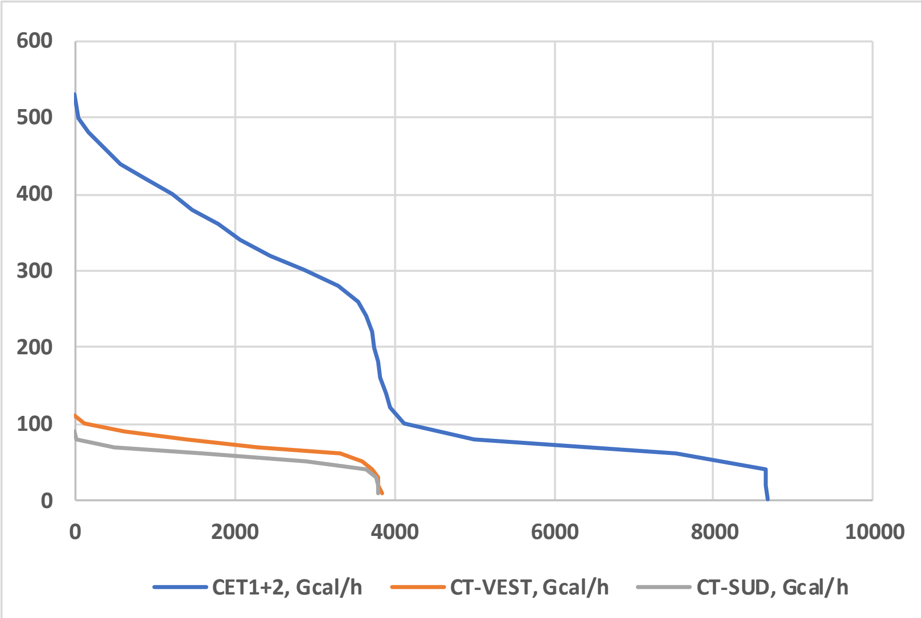
Results of the heat demand forecast analysis for 2030 are presented in Exhibit 2.

Exhibit 2: Heat Demand Forecast

Space Heating	**Area, m2**	**Demand, Gcal/y**
Average for 2016-18	9,477,000	1,354,000
Existing flats with improved efficiency due to DSM	608,000	-26,000
Returned customers	702,000	100,000
Demolished flats	-211,000	-30,000
New built flats	4,800,000	343,000
Subtotal for space heating	***15,376,000***	***1,741,000***
Domestic Hot water	**Person**	**Demand, Gcal/y**
Total people receiving DHW service in 2016-18	313,200	288,500
Returned DHW customers	174,000	160,300
Lost DHW customers due to flats demolished	-15,700	-14,400
New DHW customers in new built flats	174,000	160,300
Subtotal for DHW	***645,500***	***594,700***
Total DH Heat Demand in 2030 based on current DH heat losses		2,335,700
Reduction in Heat Losses in 2030		-95,800
Total Annual Heat Production Demand in 2030		**2,239,900**

Exhibit 3 presents the Load Duration Curves (LDC) forecast for the CET-1 and CET2, CT-Vest and CT-Sud service areas in 2030 that are used as a basis for the option analysis in this study. The peak demand is the highest point on the curve, while annual heat production is the area underneath the curve.

Exhibit 3: Load Duration Curve, Year 2030, Gcal/h



POWER DEMAND FORECAST

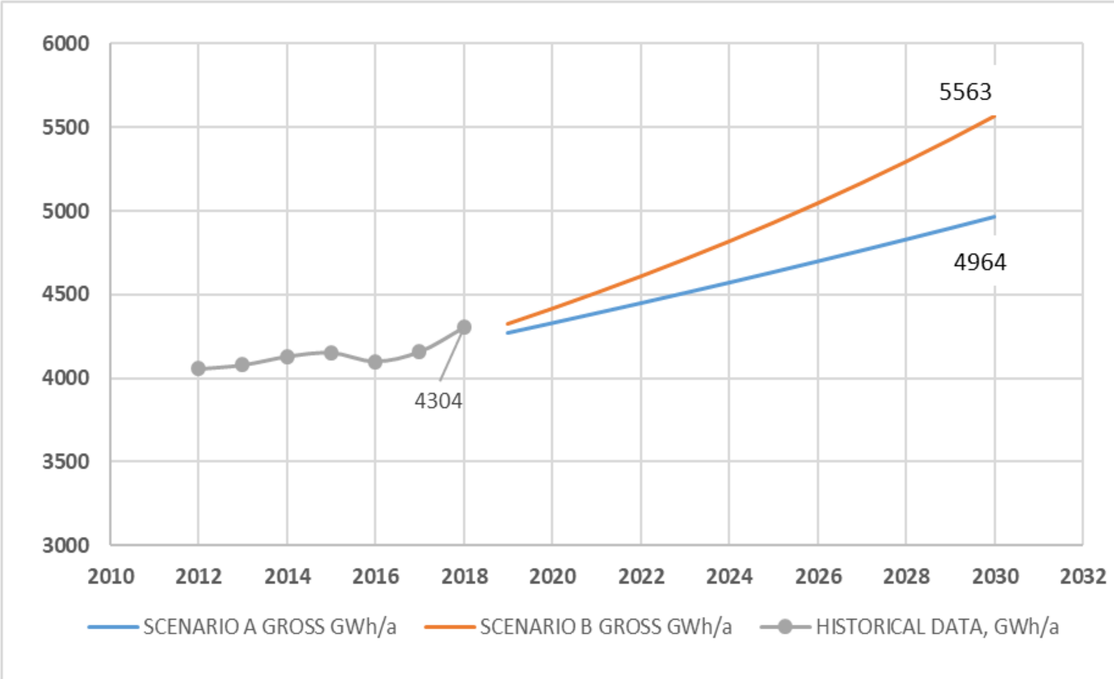
The demand forecast approach used in his study is based on 2003-2017 historical Moldova's net electricity consumption by sector of economy. It was calculated by extrapolating growth in Moldova's Purchasing Power Parity (PPP) GDP and net electricity demand during the same period. The evolution of the country's effective PPP GDP is based on reports from the Ministry of Economy and Infrastructure of the Republic of Moldova, Department of Macroeconomic Analysis and Forecasts, World Bank, and EBRD estimates.

The future power demand forecast is developed for the following range of the assumed scenarios of the future annual GDP PPP growth rates:

- Scenario A at 3% annual growth,
- Scenario B at 6% annual growth

The net values of the forecasted electricity demand are adjusted to include expected HV and LV losses. The gross electricity demand forecast (including losses) for the right bank power system is presented in Exhibit 4.

Exhibit 4: Moldova Right bank gross electricity demand forecast through 2030



Note: Starting point for above projections is a 2016-2018 3-year average.

Comparisons of Scenario A and Scenario B projections with the past studies is presented in Exhibit 5.

Exhibit 5: Comparison of electricity demand projections for 2030

Source	Power Demand, GWh/y	% Difference
Strategy 2018 – 2030	5,400	0
World Bank 2015	6,200	15%
Strategy 2013	8,500	57%
Scenario A	4,964	-8%
Scenario B	5,563	3%

The range of gross electricity demand projections in Scenarios A and B is consistent with the Moldovan government forecast for 2018-2030, and somewhat lower than the WB forecast in their 2015 study.

Peak load forecast in Exhibit 6 is developed based on the Scenario A and B of the gross electricity demand projections and an assumed escalation of 0.5% a year of the historical load factors provided by Moldelectrica SA and ANRE.

Exhibit 6: Peak load forecast for 2020-2030

Year	Scenario A		Scenario B	
	Gross Power, GWh/yr	Peak Load, MW	Gross Power GWh/yr	Peak Load MW
2030	4,964	912	5,563	1,023

1.3.3 TASK 3 - GAS AND WATER SUPPLY

This section provides results of the following tasks related to availability and forecast of natural gas and raw makeup water for the new generation capacities in Moldova. The subtask scope is presented below.

1. Natural Gas Supply: Determine the current summary and a forecast of gas supply availability from all the potential sources, based on available information, and providing the following
   - Summary of historical (at least 3 years) gas consumption, separately for all user categories in Moldova.
   - The availability of gas quantities in seasonal high and low regimes,
   - Gas pressures available for power generation.
   - Any required/considered technical improvements to the gas supply network.
   - Summary of all potential risks related to the gas supply availability, with the acceptable level of certainty.
2. Water Supply: Determine the availability, reliability, quantity and quality of technical water for the new generation capacity, considering all reasonably available sources, technologies and storage capacity, and the need for water supply system improvements and estimate of required investments.

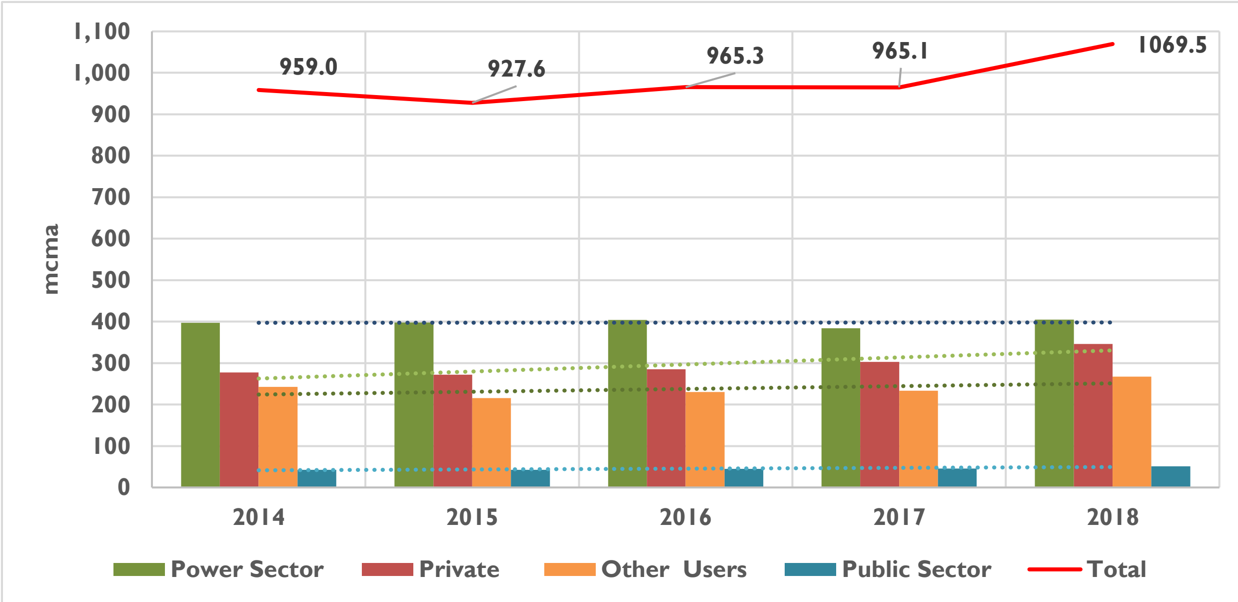
In addition, this section provides summary of a regional gas supply availability, and available capacities in close proximity to Moldova

NATURAL GAS SUPPLY

Currently all the natural gas consumed in Moldova is being imported from Russia in accordance with a contract that was signed in 2008. The contract is being extended on an annual basis, and it links gas prices for Moldova to the global market prices. An alternative source of natural gas supply to Moldova from Romania is being developed by Vestmoldtransgaz via the Iasi-Ungheni-Chisinau pipeline. Moldova is reported to have no proved commercially recoverable natural gas reserves [1]. Moldova completely relies on natural gas imports.

The overall gas consumption in the county increased during the 2014-18 period by approximately 11% (Exhibit 7), mainly due to increased consumption by the "Private Sector" and "Other Users" categories. Natural gas consumption in the Power and Public Sectors remained relatively constant during the reported period.

Exhibit 7: Natural gas consumption by sectors for 2014-2018, by ANRE



Sources of gas supply to Moldova are limited in direction as well as in origin. As discussed in Section 5, presently there are only two sources of natural gas supply, one via Ukraine and one via Romania (under construction).

GAS SUPPLY REQUIREMENTS FOR THE MOLDOVA COGENERATION PROJECT

The existing CHP sites in Chisinau and Balti are considered as likely candidates for the new generating capacities. Maximum available deliveries of the natural gas at the candidate sites and delivery pressure are presented in Exhibit 8.

Exhibit 8: Natural gas availability at the existing CHP sites

Site	Maximum available natural gas capacity, m^3/h	Site Delivery Pressure, Barg	Notes
CET-1	41,666	3	World Bank report [2]
CET-2	150,000 300,000	3 6	World Bank report [2]
CET Nord	100,000	12	Minutes of Meeting [3]

Natural gas consumption by a 450 MW net / 530 Gcal/h GTCC CHP is estimated at approximately 125,000 m^3/h. Based on the available natural gas capacity data in Exhibit 8, the CET-2 site has sufficient natural gas infrastructure to support the fuel demand of a 450 MW net / 530 Gcal/h GTCC CHP.

Natural gas consumption by a 150 MW net GTCC is estimated at approximately 30,000 m^3/h. Both CET-1 and CET Nord have sufficient natural gas infrastructure to support operation of a 150 MW net GTCC.

The natural gas infrastructure at the existing CET-1, and CET-2 and CET Nord CHP sites has sufficient capacity to support new power generation capacities considered in this study.

SEASONAL GAS PRESSURE (HI & LOW)

Seasonal data for natural gas pressure in transmission pipelines has not been reported by Moldovagaz. There is data available about seasonal gas pressure fluctuation at CET-1 and CET-2 plants in Chisinau. However, this data is taken downstream of the pressure reducing stations at CET-1 and CET-2, and thus it could not be used as representative for the transmission and distribution network seasonal pressure fluctuations. Furthermore, Tokuz-Kainary-Mereny pipeline in Southern Moldova (Exhibit 115) with total length of 62.74 km was completed in 2007. This pipeline ensures the reliability of maintaining constant pressure in the Chisinau area during the heating season period of maximum gas consumption.

FORECAST OF GAS AVAILABILITY

Following the completion of the ongoing infrastructure project in Turkey, Greece, Bulgaria and Romania the sources of supply of natural gas to Moldova are expected to become diversified.

There is a potential possibility for LNG to be supplied to Moldova from the LNG terminal in Greece. LNG supply could become viable once the required pipeline interconnectors are in place, especially with the Alexandroupolis LNG project.

Development of new pipeline interconnectors could open Caspian and Mediterranean, and even Algerian natural gas markets to Moldova. Reversing the existing Trans Balkan pipeline flow could provide for the possibility of Russian gas supply via Turkey.

Moldova could co-finance development of natural gas storages in Ukraine and Romania to secure reliability of the country's gas supply, since natural gas storages are not available in Moldova.

FORECAST OF MOLDOVA NATURAL GAS CONSUMPTION

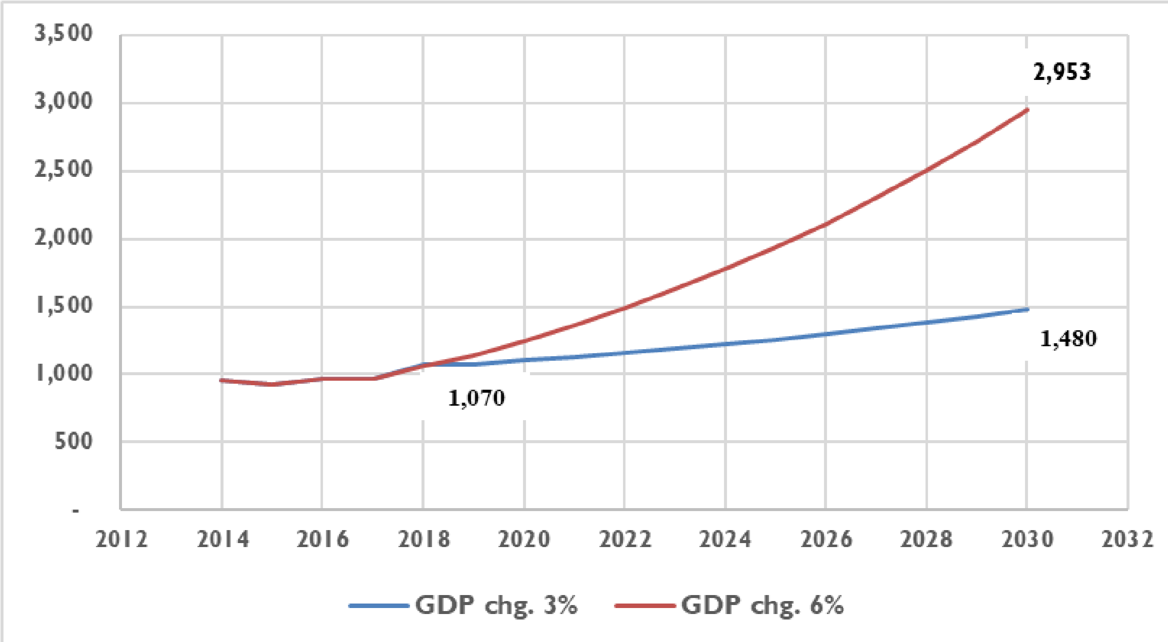
An Estimate of the natural gas demand forecast for the Moldova Private, Other and Power consumer groups has been performed using statistical analysis that considered the historical correlation of the natural gas consumption by the Private, Other and Power consumer groups with the Moldova population, GDP per capita, and annual percent change in GDP. An average of 4.6% of the total demand was assumed for the Public consumer group.

Moldova's natural gas consumption is expected to follow its national GDP trend. The following range of annual GDP growth has been assumed for the natural gas demand forecast.

- Scenario A at 3% annual growth,
- Scenario B at 6% annual growth

Graphic representation of the natural gas demand forecast scenarios is shown in Exhibit 9.

Exhibit 9: Natural Gas Demand Forecast, MCM/Yr



TECHNICAL WATER FOR NEW GENERATING CAPACITIES

Fossil power plants consume significant amounts of water for their operation. Thus, availability of water in sufficient quantities is one of the critical factors in developing new power generating capacities. This section presents an analysis of potential water sources and uses for the purpose of developing new thermoelectric generating capacities in Moldova.

Under the Moldovan law, the collection and use of water from surface and underground sources for technical and industrial purposes, such as a GTCC or CHP power plant, as well as a wastewater discharge falls under the requirements of "Special Water" use that requires a permit.

Based on the preliminary thermodynamic and water balance analyses of a new 400 MW CHP plant that utilizes GTCC cycle, equipped with evaporative cooling tower and providing heat to the Chisinau district heating system, its cooling system capacity is estimated at approximately 100 MWth, while supporting a district heating load of 400 Gcal/h. Cooling system duty in condensing mode is estimated at approximately 130MWt. The amount of raw water necessary to compensate for the evaporative cooling tower and steam-water cycle losses is estimated at approximately 300,000 m^3/yr for a plant capacity factor of 85%. The waste water discharges to the sewer system are estimated at approximately 80,000 m^3/yr. The cooling system duty for a new electric power-only 160 MW GTCC unit is estimated at approximately 50 MWth.

From the stand point of raw water availability, the existing CHP sites in Moldova present the best candidate sites for the new generating capacities. These sites already have permitted municipal sources for the raw water supply and waste water discharge. For the purposes of this assessment, it is assumed that the new generating units that are to be located on the existing sites (brownfield sites) should be designed with raw water makeup and waste water discharge requirements that will not exceed the currently available raw water and waste water capacities of the municipal sources and permits at these sites. The new generating capacities on the brownfield sites could be designed with either evaporative cooling system or ACC, as long as the raw water makeup and the waste water discharge flow rates are within the existing site limits.

The estimated raw water demand and waste water discharge requirements for the new generating capacities at CET-2 site can be satisfied by the existing SA Apa Canal municipal water and sewer systems. An evaporative cooling system could be considered for a new power-only GTCC unit if located at the CET Nord site.

The approach of utilizing the existing water sources at the brownfield sites and air cooling at the greenfield sites should streamline the permitting process for the new power units (i.e., utilize the existing "Special Water Use" permit) and reduce/eliminate additional capital investments attributed to the raw water and waste water utilities.

1.3.4 TASK 4 - LAND AND STRUCTURAL ISSUES

This section provides a high-level assessment and ranking of the possible suitable locations for the new generating capacities in Moldova. This assessment is primarily focusing on proximity and availability of the required utilities interconnections, such as high voltage electric substation, district heating system, natural gas connection, makeup water and waste water systems. It also takes into account any potentially reusable existing structures, facilities and systems and available space on the existing sites.

The sites are evaluated and ranked utilizing a qualitative scoring system based on the following criteria:

- Site characteristics: land availability, site location relative to sensitive noise receivers, environmental, topography, and geology, groundwater, seismic, that may result in additional site preparation requirements.
- Infrastructure: site access (road and rail), proximity to water supply and effluents discharge systems, natural gas piping, and HV lines/substation.
- Engineering: DH network, existing facilities on site suitable for re-use or requiring demolition, water treatment requirement, etc.

CANDIDATE SITES

Candidate sites are presented in Exhibit 10 and have been selected based on discussions with the project stakeholders in Moldova that included Termoelectrica, Moldelectrica, Ministry of Economy and Infrastructure, and CET Nord. CT Vest and CT Sud sites have been included based on recommendations of the recently completed World Bank study [2].

Exhibit 10: Candidate Sites

Site	Site Status	Current Configuration	Configurations for Consideration	Location	Coordinates
CET-1	Brownfield	CHP	Power Only	Chisinau	47.02555, 28.86737
CET-2	Brownfield	CHP	CHP	Chisinau	47.02986, 28.89399
CT-VEST	Brownfield	Heat Only	CHP (note 2)	Chisinau	47.04235, 28.8071
CT-SUD	Brownfield	Heat Only	CHP (note 2)	Chisinau	46.99241, 28.82325
CT East	Brownfield	Power Only [Not currently in operation]	Power Only	Chisinau	46.97171, 28.91604
CET Nord	Brownfield	CHP	Power Only	Balti	47.74934, 27.89398

Notes:

1. Brownfield site status designates a site of the existing power plant.
2. CT-VEST and CT-SUD can operate all year round as a CHP with a total installed heat capacity of approximately 50 Gcal/h.

Five sites in the area of Chisinau and one site in Balti are identified as having promise to be a host site for the new thermal electric generation capacities (Exhibit 10). However, the sites are not equal when it comes to the value of capacity utilization on site in meeting district heating demand as explained below.

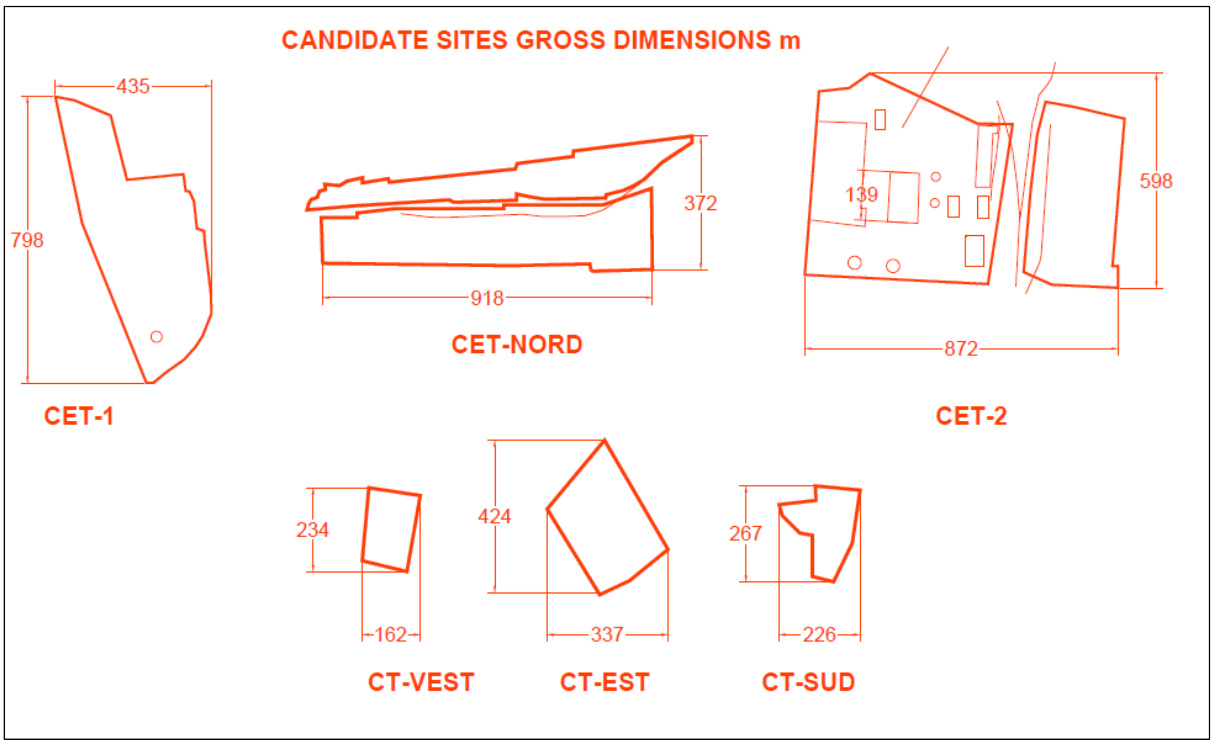
Among the sites in the Chisinau area, CT Vest and CT Sud sites have an opportunity to produce heat for the district heating system all year around. This is due to the hydraulic situation of the Chisinau district heating system, which during the heating system is divided into the three operating service areas/loops: CET-1/CET-2, CT Vest and CT Sud. During the off-heating season, Chisinau district heating system operates in a single loop providing only domestic hot water service. During this time CET-1, CT Vest and CT Sud can provide heat to the system. Hot water load during the off-heating season is less than 50 Gcal/h. That is why operation of the CET-2 units during the off-heating season is not practical due to the size of its generating units. Currently CET-1 operates during the off-heating season months providing hot water service in an efficient cogenerating mode. However, operation of CET-1 during the heating season is relatively uneconomical as compared to the CET-2. This situation makes CT Vest and CT Sud sites uniquely suitable for the relatively small cogenerating units with total heat capacity of approximately 50 Gcal/h that could be in operation all year around. CET-1 site could be a contender to host a power-only new unit, similarly to CET Nord.

The CT East site could be potentially utilized to accommodate either a CHP unit, or a power-only unit. CT East is designed to be connected to the CET-1/CET-2 district heating loop. However, CT East currently is not in operation. Little information is available about the condition of its electric power, fuel gas, water and district heating infrastructure. However, the CT East site appears to have available space (although it was not reported) and adequate site access. It is likely to have the required environmental permits and is located some distance from the residential areas. This makes the CT East site a suitable contender for a new power-only unit. CT East has no unique advantage to be operated as a CHP and would compete against the larger CET-2 in the winter. Thus, the CT East will not be considered for CHP operation, but only the Power-only option.

All six candidate sites were carried into the qualitive evaluation. The highest scoring sites were carried into the Task 6 technology options section.

Approximate layouts and dimensional envelopes of the candidate sites have been derived from the available aerial images, maps and schematics and are presented in Exhibit 11.

Exhibit 11: Approximate Dimensions of the Sites



Estimates of the approximate total and available space at the candidate sites is presented in Exhibit 12.

Exhibit 12: Approximate Available Area at candidate Sites

Site	Total Area, hectares	Available area, hectares
CET-1	16.9	2.16
CET-2	29.4	7.31

Site	Total Area, hectares	Available area, hectares
CT-VEST	2.8	0.2
CT-SUD	3.3	Note 3
CT East	7.4	NR
CET Nord	30	2

Notes:

1. NR – Not reported. Although the available area was not reported, it is believed to be adequate for CHP and/or Heat only options being considered particularly since the plant is not currently in operation.
2. Layouts of the CT Vest and CT SUD sites will need to be redesigned to accommodate a new power plant.
3. At CT SUD the new generating equipment can be located in the existing steam boiler building, requiring removal of the existing steam boilers [2].

Approximate area requirements of the new power plant layouts are summarized in Exhibit 13.

Exhibit 13: Approximate Area Requirements for Thermal Plants

Unit Type	Unit Capacity, MW	Length, m	Width, m	Area, m^2	Area, hectare
GT SC	100-120	66	55	3,630	0.4
GTCC	150-170	120	81	9,720	1.0
GTCC	300-320	168	115	19,320	1.9
RICE	21-31	70	60	4,200	0.4

Note: Space requirements for the Reciprocating Internal Combustion Engine (RICE) plants is estimated based on Worley in-house information.

It can be seen, based on comparison of the available space at CET-1, CET-2, CT Vest, CT Sud, and CET Nord sites (Exhibit 12) with the approximate area requirements of the sample power plant configurations that these candidate sites should have sufficient space to facilitate addition of the new power units. Space sufficiency at the CT East site cannot be ascertained at this time, as its available space has not been reported.

CANDIDATE SITES EVALUATION AND SELECTION

Five sites in the area of Chisinau and one site in Balti were identified as having promise to be a host site for the new thermal electric generation capacities (Exhibit 10). All the sites are potentially suitable for a CHP configuration. However, CHP operation at the CET-, CET Nord and CT East sites is judged as not economical. CET-1, CT East and CET Nord sites are considered for the new electric power-only units.

Several evaluation attributes are selected to rank the candidate sites, and a qualitative analysis conducted. Each evaluation parameter received a weighting of 1 to 5, with 5 reflecting the greatest importance. Site specific scores were assigned for each of the evaluation areas with scores ranging from 1 to 10, with 10 being most favorable. The total site score was developed by summing the weighted scores for all of the evaluation parameters. Thus, a higher score reflects a better suitable site.

Each of the evaluation attributes is discussed below:

- CET-1, CET-2, and CET Nord sites were given identical score for available space. CT Vest site was given somewhat lower score. CT Sud and CT East were given lower scores, as layouts of the CT Vest and CT SUD sites will need to be redesigned to accommodate a new power plant, and limited information is available about CT East.
- CET-1, CET-2, and CET Nord are located in what appear to be industrial zones of Chisinau and Balti. However, over the years residential housing has moved closer to the industrial zones. These sites given identical score for proximity to residential areas. There are no residential areas in the vicinity of CT East site, and it received the highest score in this category. CT Vest and CT Sud were given the lowest score as these sites are located fairly close to the residential areas.
- Topographical conditions have been assessed through site visits, the topographical maps, and photographs. All sites were given identical score in this category as judged to require the approximately the same earth moving work, and heights of stacks. All sites are also expected to have similar geological and seismic conditions.
- The environmental impact of the gas-fired power plant is expected to be minimal and relatively independent of the site location. All new plants are expected to be designed to meet the European Union environmental regulations.
- Access roads and railway scoring reflects the classification of the road providing access to the site boundary and reflects proximity of the rail to the proposed site. CET-2, CT East and CET Nord have been given a higher score as having rail road access on site. However, the condition of the rail lines is not known.
- Water supply is a highly weighted parametric area in light of the large quantities of water that are required for cooling. All of the candidate sites have access to municipal water sources that can provide sufficient makeup water supply and effluent offtake and thus received an identical rating, except for CT East site, for which water supply information is not available.
- Natural gas fuel supply is another highly weighted parametric area as high reliability and large quantities fuel gas supply are required for a power plant operation. CT Vest and CT Sud sites received a higher score in this category as potential sites for reciprocating engine units only that require a low-pressure gas. All other sites received a lower score as potential candidate sites for gas turbine units that require fuel gas pressure of approximately 45 Barg. Currently all the sites receiving natural gas at 3 Barg. Gas turbine plants will require large gas booster compressors, which should add capital and operating costs. The adequacy of the natural gas flow is determined in Task 6, where the flowrate is shown to be adequate for all sites.
- CET-1, CET-2 and CET Nord sites were given identical scores for electric connections. These sites currently are connected to 110kV transmissions lines and potentially can be connected to 330kV network. CT Vest and CT Sud were awarded the lowest scores in this category as these sites are connected to 6kV network and may potentially be required to be connected to a high voltage system, at additional capital expenditures. CT East was given a somewhat lower score due to the limited information.

- CET-2, CT Vest and CT Sud sites were given identical scores for proximity to the district heating network connections, as having the district heating connections on site. CET-1, CT East, and CET Nord sites are not scored in this category as they are envisioned to host a power-only unit.
- Value of capacity utilization on site in meeting DH demand category evaluates sites on their potential of maximizing district heating revenues. CT Vest and CT Sud sites received the highest scores in this category as new units on both sites have an opportunity to operate all year around in efficient cogenerating mode. CET-2 site received a lower score, as a new unit on this site could only operate in cogenerating mode during the heating season. CET-1, CT East, and CET Nord sites are not scored in this category as they are envisioned to host a power-only unit.
- All sites, except CT East and CT Sud sites were given an "existing facilities reuse score" of 5, or weighted score of 10. CT East site was given a lower score because of due to the limited information. CT Sud was given a lower score of 3, as at CT SUD new generating equipment can be located in the existing steam boiler building, requiring removal of the existing steam boilers.
- For "Extensive demolition requirement" category all sites received identical score, except for the CT East site due to the limited information.

The results of the evaluation are presented in Exhibit 14.

Exhibit 14: Qualitative Assessment for Site Selection

	Evaluation Parameters	**Weight Factor**	**Weighted Score**					
1	**Site Characteristics**	**1 to 5**	**CET-1**	**CET-2**	**CT Vest**	**CT East**	**CT Sud**	**CET Nord**
	Available footprint (plant, laydown)	3	18	18	15	9	9	18
	Proximity to residential area.	2	14	14	10	16	10	14
	Topography, Geology, Hydrology, Earthquakes	3	15	15	15	15	15	15
	Environmental Issues	5	25	25	25	25	25	25
2	**Infrastructure criteria**							
	Access Roads and railways	3	12	18	12	18	12	18
	Water access & availability	4	24	24	24	16	24	24
	NG Fuel supply sources	4	20	20	32	20	32	20
3	**Engineering criteria**							
	Distance to electrical interconnection.	5	20	20	10	15	10	20
	Distance acess to district heating network.	5	0	25	25	0	25	0
	Value of capacity utilization on site in meeting DH demand	5	0	40	50	0	50	0
	Existing facilities to re-use	2	10	10	10	4	6	10
	Extensive demolition requirement	2	6	6	6	4	6	6
	CUMULUTIVE WEIGHTED SCORE for CHP sites			**235**	**234**		**224**	
	FIINAL RANKING of CHP sites			**1**	**2**		**3**	
	CUMULUTIVE WEIGHTED SCORE for Power only sites		**164**			**142**		**170**
	FIINAL RANKING of Power only sites		**2**			**3**		**1**

RECOMMENDATIONS

Among the CHP sites none of the resulting scores would preclude any of the three sites from being considered in Task 6. As such all three CHP sites (CET-2, CT-Vest, and CT-Sud) will be considered in Task 6. For the Power-only sites, the higher scores are more likely to yield a reduced capital requirement. CET-1 and CET Nord scored closely, and both are recommended for final site selection. CT East site is not recommended for final selection, unless additional information is provided that supports it's consideration.

1.3.5 TASK 5 - LEGAL AND REGULATORY CONSIDERATIONS

The objective of this task is to:

- Identify legal/ regulatory issues concerning construction and operation of heat and power generation and supply in Moldova and EU
- Summarize legal and regulatory issues to be addressed in next phase of feasibility assessment, planning, procurement, and construction. The summary shall include social and environmental issues, as well as licensing, and certification process required by current Moldovan law and EU directives
- Highlight steps for compliance with all requirements
- Note/ appraise potential roadblocks/ difficulties in relation to heat and power generation options in Moldova

Moldova is highly dependent on electricity imported from Ukraine or produced in the Transnistria region (over 80% of the country's total energy demand). In order to ensure the RoMs security of supply, the new Greenfield project should be awarded strategic importance. The government should support its implementation through legislative development, enabling a fast-paced implementation.

The European energy legal system, in particular the Third Energy Package, should be fully implemented in the Republic of Moldova. Currently, the energy legal system in place in Moldova is not fully compliant with the system applicable in the ENTSO-E countries, although there is an evolution in the right direction.

Moldova has been taking necessary steps towards transposing the Energy Community acquis, though implementation is still at an early stage and behind schedule, having reached 44% overall implementation, according to the Energy Community Secretariat 2019 Annual Report. On the plus side, RoM has declared its commitment to implement the needed reforms of the electricity market.

Specifically, the legal framework (primary and secondary regulations) needs to be updated and correlated in order to accommodate the construction of new electricity generation assets. Among others, Moldova still needs to address:

- Revision of the Electricity Law 107/2016;
- Adoption of Electricity wholesale market rules;
- Transposition into national legislation of the Directive 2001/80/EC on the limitation of emissions of certain pollutants into the air from large combustion plants
- Option to allocate the increase of the country's emissions levels by 2030 to a new gas-fired power generation asset

In terms of potential risks [4], any future investor would need to consider the following:

- **Location:** availability (difficulties regarding access to a particular location), unforeseen location or ground conditions (e.g. discovery of archaeological remains and/ or national heritage), approval of the necessary documents (e.g. delays in obtaining the necessary approvals/ authorizations in the terms provided), property title (difficulties in the land acquisition process from the owners and/or obtaining the right to use the land)
- **Design and construction:** discovery of archaeological remains and/or national heritage on a site that prevents construction work causing delays and increasing project costs
- **Financing:** increase of the costs of the initial investment (due to changes in legislation, policy or of other nature, the initial investment becomes greater than estimated)
- **Political/legislative:** change of field-specific legislation, withdrawal of complementary support (e.g. changes in the strategy, tactics and current actions of the political factors in their own country (at national, regional and local level), from the countries with which the company has direct and indirect contracts)
- **Environmental:** adjacent properties unavailable for project implementation (e.g. the emergence of buildings or other types of property adjacent to the location, that do not allow the development of the project due to environmental contamination)

1.3.6 TASK 6 - TECHNOLOGY OPTIONS

The candidate projects considered for the technical options evaluation have been selected to meet the technical parameters (Exhibit 15) and other design criteria as specified in Section 8.1. The CHP Projects 1 through 4 provide a range of potential solutions for satisfying Chisinau DH system heat demand currently primarily supplied by CET-2, while co-generating power. Project 1 and Project 2 are configured to maximize electric power generation by operating in condensing mode during the off-heating season. Project 3 and Project 4 design allows for operation only during the heating season, with Project 3 equipped with a backpressure steam to maximize a fuel utilization efficiency, and Project 4 that is not equipped with a steam turbine system to minimize capital costs.

The Project 5 configuration follows the recommendations of the World bank study [2] with the installation of new RICE units. Project 6 is a state-of-the-art single shaft GTCC unit while Project 7 is a multi-shaft GTCC unit configured to meet technical criteria specified in Exhibit 166.

The gas turbine and RICE models selected for all the projects are considered best available state-of-the-art technologies for the specified nominal output range and application, as these are commercially available machines with the highest reported efficiencies for the 50Hz service.

All Projects will be utilizing natural gas as a primary fuel, with the Ultra-Low Sulfur Diesel (ULSD) as a backup fuel to meet the Euro V standard for fuel. While Moldova as an EU accession country has been granted certain temporary exemptions to allow for transition to the ULSD, it is expected that Moldova will have to fully comply with the EU environmental regulations by 2030, when the projects are envisioned to be commissioned.

Exhibit 15: Technical Attributes of Candidate Projects

Project	Cycle	Configuration	Target Site	Estimated Space, m	Nominal Output, MWe/Gcal/h	Comments
1	CHP	3GT1 x 3HRSG x 1STG (condensing)	CET-2	200 x 180	480/ 530	GT1 is assumed based on MHPS H-100
2	CHP	2GT2 x 2HRSG x 1STG (condensing)	CET-2	215 x 170	458 / 477	GT2 is assumed based on GE 9E.04
3	CHP	2GT2 x 2HRSG x 1STG (backpressure)	CET-2	215 x 140	453 / 483	
4	CHP	2GT2 x 2HRSG	CET-2	194 x 124	298 / 530	
5	CHP	2RICE x 2WHR, 3RICE x 3WHR	CT Sud CT Vest	60 x 60 70 x 60	20 / 24 30 / 36	RICE is assumed based on Jenbacher J920
6	GTCC	1GT1 x 1HRSG x 1STG	CET Nord	190 x 150	150 / 0	Single shaft configuration
7	GTCC	1GT2 x 1HRSG x 1STG	CET Nord	200 x 150	219 / 0	Multiple shaft configuration

Notes:

1. Legend
    a. CHP – Combined Heat and Power
    b. GTCC -Gas Turbine Combined Cycle
    c. RICE – Reciprocating Internal Combustion Engine;
    d. HRSG – Heat Recovery Steam Generator
    e. STG – Steam Turbine Generator
    f. WHR – Waste Heat Recovery System
2. The estimated space requirements include space for an associated switch yard.

The above projects are combined into the following options (Exhibit 16) that are configured to satisfy the target technical parameters specified in Exhibit 166. The candidate technical options are configured to utilize the same gas turbine model (GT1 or GT2) within an option to streamline future spare parts and GT maintenance services procurement, and operators' training.

Exhibit 16: Candidate Technical Options Matrix

Options	Project 1	Project 2	Project 3	Project 4	Project 5	Project 6	Project 7
Option 1	X				X	X	
Option 2		X			X		X
Option 3			X		X		X
Option 4				X	X		X

The estimated annual heat production by each project is summarized in *Exhibit 17*.

Exhibit 17: Annual Heat Production

Options	Heat production, 1000 Gcal / year							
	Project 1	Project 2	Project 3	Project 4	Project 5	Project 6	Project 7	Total
Option 1	1,474				766			**2,240**
Option 2		1,474			766			**2,240**
Option 3			1,474		766			**2,240**
Option 4				1,474	766			**2,240**

The estimated annual electric power generation by each project is presented in *Exhibit 18*.

Exhibit 18: Annual Electric Power Generation

Options	Electric Power Generation, 1000 MWh / year							
	Project 1	Project 2	Project 3	Project 4	Project 5	Project 6	Project 7	Total
Option 1	2800				437	946		**4,183**
Option 2		2,609			437		1,313	**4,359**
Option 3			1,535		437		1,313	**3,285**
Option 4				1,101	437		1,313	**2,851**

The overall fuel utilization efficiency (Exhibit 19) is defined as: (net plant electric output + all useful heat output) / (Total fuel LHV input). It includes thermal energy and fuel consumption from hot water boilers.

Exhibit 19: Overall Fuel Utilization Efficiency

	Option 1	Option 2	Option 3	Option 4
Overall Fuel Utilization Efficiency	70.8%	70.8%	75.8%	74.7%

Capital expenditures (CAPEX) have been developed utilizing Thermoflow Plant Engineering and Construction Estimator (PEACE) software. PEACE is extensively used in the industry for relative pricing comparison of options and screening analysis. CAPEX estimates performed by PEACE are based on the same underlying assumptions for all the projects, and therefore, all the options are compared on a level playing field. Any changes in the assumptions will impact CAPEX for all the projects in similar fashion. As such, these CAPEX are not investment cost estimates, and should only be considered for the relative comparison purposes. CAPEX summaries for each project and option are presented in Exhibit 20.

Exhibit 20: CAPEX Summary

Description	Units	Option 1		
		Project 1	Project 5	Project 6
EPC Cost	x1000 US$	406,900	48,800	164,100
Owner's development and allowance	x1000 US$	36,600	4,400	14,800
Owner's Total Cost per Project	x1000 US$	443,500	53,100	178,900
Total Costs per Option	**x1000 US$**	**675,500**		
Description	**Units**	**Option 2**		
		Project 2	**Project 5**	**Project 7**
EPC Cost	x1000 US$	367,900	48,800	189,700
Owner's development and allowance	x1000 US$	33,100	4,400	17,100
Owner's Total Cost per Project	x1000 US$	401,000	53,100	206,800
Total Costs per Option	**x1000 US$**	**660,900**		
Description	**Units**	**Option 3**		
		Project 3	**Project 5**	**Project 7**
EPC Cost	x1000 US$	333,500	48,800	189,700
Owner's development and allowance	x1000 US$	30,000	4,400	17,100
Owner's Total Cost per Project	x1000 US$	363,500	53,100	206,800
Total Costs per Option	**x1000 US$**	**623,400**		
Description	**Units**	**Option 4**		
		Project 4	**Project 5**	**Project 7**
EPC Cost	x1000 US$	231,500	48,800	189,700
Owner's development and allowance	x1000 US$	20,800	4,400	17,100
Owner's Total Cost per Project	x1000 US$	252,400	53,100	206,800
Total Costs per Option	**x1000 US$**	**512,300**		

ECONOMIC ANALYSIS

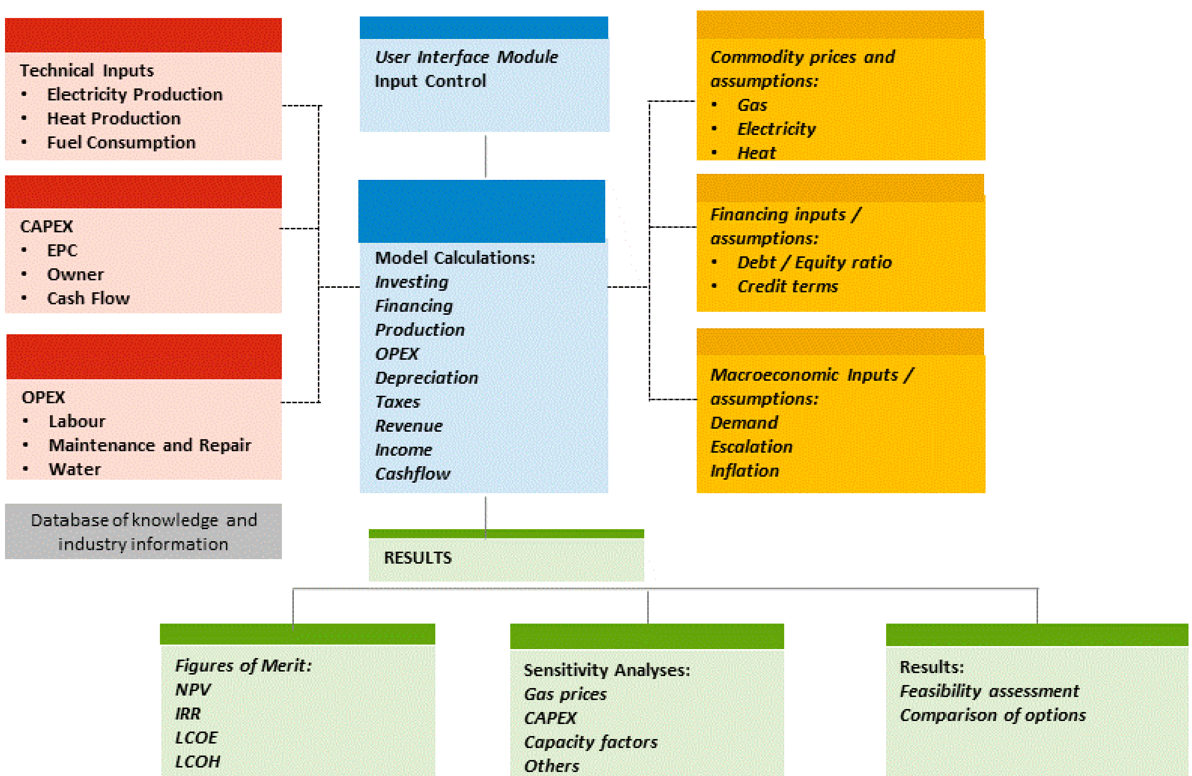
The project is expected to reach financial closure in the first half of 2026 and start construction in the second half of the same year. Then, the project is expected to achieve commercial operation at the beginning of 2030.

For the purposes of this comparative economic assessment, to avoid uncertainties related to forecasting future price escalation of plant equipment, materials, labor, commodities (gas, electricity, heat), etc., the options are compared based on an assumption that the construction of all projects will start now, and the projects will be in commercial operation at end of the construction period.

This approach is reasonable as Capital Expenditures (CAPEX) and Operating Expenditures (OPEX) are available in 2019 prices, and there will be no need to predict their escalation through 2026. Furthermore, today's commodity prices are assumed in the first year of project operation. Hence, all values are presented in 2019 USD. All other economic analysis assumptions are specified in Section 8.4.1.

Economic analyses are performed utilizing a financial model, which is structured as presented in Exhibit 21.

Exhibit 21: Financial Model Structure



FIGURES OF MERIT

The following figures of merit are calculated as a result of the economic analysis modeling:

NPV (Net Present Value) represents the value of future cash flows today (or at the base discounting year). This value is calculated by applying the required discount rate (typically the industry discount rate, the firm's cost of capital, or the required rate of return). The positive NPV is an indicator of the project's feasibility. NPV is calculated at 5% discount for the Base Case.

IRR (Internal Rate of Return) is the discount factor at which net present value of the project equals to zero, or at which NPV of negative cash flow equals the NPV of positive cash flow of the project. The IRR is usually compared with the expected rate of return from the project and is an indicator of the efficiency, quality and yield of project investments. IRR will be calculated at net project cash flow, which will consider equity investments, debt repayments, revenue, operational costs, taxes, etc.

LCOE (Levelized Cost of Electricity) is represented by the cost at which the present value of all revenues from electricity generation is equal to the present value of all expenditures for its production (including construction and operation). LCOE is calculated for the whole lifetime of the project, and represents the NPV of expenses divided by the NPV of production, or by applying the formula:

$$LCOE = \frac{\sum_{i=1}^{N} \frac{(Annual\ Cost)_i}{(1+d)^{t}i}}{\sum_{i=1}^{N} \frac{(Annual\ production)_i}{(1+d)^{t}{}_i}}$$

Where d is the discount factor.

LCOH (Levelized Cost of Heat) is calculated in the same way as the LCOE but considering the expenses and amount of the heat production.

The allocation of fuel costs to electricity and heat is made applying the methodology described in Section 8.4.1. CAPEX and OPEX are split between the products applying the same % distribution as calculated for the fuel.

BASE CASE RESULTS

The Base Case analysis is formed based on the input data and assumptions presented above regarding the commodity prices, capital costs, electricity production, discount factor. The Base Case parameters are summarized below. Sensitivity analyses are performed for changes in these input parameters.

Exhibit 22: Base Case Economic Parameters

Parameter	Values for the Base Case
Natural Gas Price, year 1	240 USD/1000 m^3
Electricity Price, year 1	65 USD/MWh
Heat Price, year 1	30 USD/Gcal
Capacity factor for Projects 6 and 7	75%
Capital Costs	As per Exhibit 20
Discount Factor	5%

The results of the economic analysis are provided in *Exhibit 23*.

Exhibit 23: Economic Analysis Results

Figure of Merit	Units	Option 1	Option 2	Option 3	Option 4
NPV	mln. USD	$370	**$439**	$295	$217
IRR	%	13.04%	**14.55%**	12.00%	11.38%
LCOE	USD/MWh	60.18	**59.12**	60.07	61.14
LCOH	USD/Gcal	26.62	**26.36**	27.36	28.13

Option 2 is the favored option based on all four (4) economic evaluation criteria (NPV, IRR, LCOE, and LCOH).

SENSITIVITY ANALYSIS

A sensitivity analysis allows for the examination of the robustness of the Base case ranking considering variability of economic input assumptions. Sensitivity analyses have been performed for the range of economic input parameters presented in Exhibit 24 with detailed results presented in Section 8.4.4. The results demonstrate that Option 2 is robust and remains the favored option through the analyzed range of parametric sensitivities.

Exhibit 24: Economic Sensitivity Matrix

Parameter	Value for the Base Case	Sensitivity
Natural Gas Price, year 1	240 USD/1000 m^3	+/- 20%
Electricity Price, year 1	65 USD/MWh	+/- 20%
Heat Price, year 1	30 USD/Gcal	+/- 20%
Capacity factor for Projects 6 and 7	75%	65% 95%
Capital Costs	As per Exhibit 20	+/- 20%
Discount Factor	5%	0%, 2.5%, 7.5%, 10%

RANKING OF THE OPTIONS

Ranking of the options in Exhibit 25 is based on IRR, LCOE and LCOH and takes into consideration the sensitivity analysis results.

Exhibit 25: Ranking of the Options

Figure of Merit		**Option 1**	**Option 2**	**Option 3**	**Option 4**
IRR	%	13.06%	14.55%	12.00%	11.38%
LCOE	USD/MWh	60.18	59.12	60.07	61.14
LCOH	USD/Gcal	26.62	26.36	27.36	28.13
Ranking					
IRR		2	**1**	3	4
LCOE		3	**1**	2	4
LCOH		2	**1**	3	4
Summary Ranking		2	**1**	3	4

Option 2 is ranked as the best option, closely followed by Option 1.

Option 2 is the best option in all sensitivity cases. Thus Option 2 appears to be a robust project since it retains its first-place ranking under many different project conditions. However, risks related to this option shall be further investigated. The risk analyses may prove Option 1 to be the optimum solution.

The reduced sensitivity of Option 3 to low gas prices may put this option in the list for further consideration as well. That said, a reduced gas price also improves the IRR and economic performance of the highest ranking Option 2 and Option 1 projects.

1.3.7 RECOMMENDATIONS

Both Options 1 and Option 2 are recommended for further evaluation in the detailed study. A summary of the technical and economic attributes of the recommended options is presented Exhibit 26.

Exhibit 26: Technical and Economic Attributes of Recommended Options

	Option 1	**Option 2**
Projects		
CET-2:	3GT1 x 3HRSG x 1STG (condensing) 480 MW net 530 Gcal/h max	2GT2 x 2HRSG x 1STG (condensing) 458 MW net 477 Gcal/h max
CT Sud: CT Vest:	2RICE x 2WHR, 3RICE x 3WHR 50 MW net 60 Gcal/h max	2RICE x 2WHR, 3RICE x 3WHR 50 MW net 60 Gcal/h max
CT Nord:	1GT1 x 1HRSG x 1STG 150 MW net	1GT2 x 1HRSG x 1STG 219 MW net
Nominal Installed Capacities	680 MW net 590 Gcal/h max	727 MW net 537 Gcal/h
Annual Heat production, Gcal/y	2,240,000	2,240,000
Annual Electric Power generation, GWh/y	4,183	4,359
% of Projected Annual Electric Power Demand for 2030		
Scenario A	84%	88%
Scenario B	75%	78%
CAPEX, million USD	675.5	660.9
NPV, mln. USD	$370	$439
IRR, %	13.04%	14.55%
LCOE, USD/MWh	60.18	59.12
LCOH, USD/Gcal	26.62	26.36
Overall Ranking	**2**	**1**

2 INTRODUCTION/PROJECT OVERVIEW

2.1 OBJECTIVE

The main objective of the Assessment of Local Power Generating Options in Moldova Project is to assess the feasibility of investment into local high efficiency gas-fired power generation capacity to increase the security of the electricity supply in Moldova through diversification of sources and potentially to provide a reliable high efficiency heat source for the Chisinau District Heating (DH) system and to ensure provision of balancing service to the Moldovan grid.

In order to determine the feasibility of investment into local power generation and more reliable heat supply to urban areas, an assessment of all aspects of such undertaking was performed, including electricity and heat load, capacity needs, impact on the national grid operation, the need for network related Investment in line with the long term network development plans, fuel availability, applicable technology, legal and regulatory conditions, social and environmental consideration, investment sequencing for new and existing capacity and its size, cost and benefit analysis and potential ownership and financing structure.

Worley efforts were closely coordinated with the Government of Moldova and other stakeholders, e.g. SA Moldelectrica, SA Termoelectrica, Moldovagaz, etc. and their valuable input was considered during the development of this study.

2.2 APPROACH

The approach taken by Worley during the implementation of the scope of work considered six tasks fulfilled in the following way.

The activities required to fulfill the project objectives have been divided by USAID into two major Contract phases with a total of twelve tasks and two reports. Each phase has six tasks and a report. The two phases are designated as:

- The first phase, titled “Conceptualization” (CLIN 01)
- The second phase, titled “Detailed Study” (CLIN 02)

The results of the first phase report will be evaluated by USAID to determine if the second phase tasks will be authorized for execution.

The twelve tasks associated with the project are listed in Exhibit 27.

Exhibit 27: Phase and Project Tasks

Phase 1 Conceptualization Tasks (CLIN 01)
Task 1: Assessment of existing CHPs and related DH facilities
Task 2: Heat and Electricity Demand and Supply
Task 3: Gas and Water Supply
Task 4: Land and Structural Issues

Task 5: Legal and Regulatory Consideration
Task 6: Technology Options
Phase II Detailed Study Tasks (CLIN 02)
Task 7: Utilities (Gas Supply, Water supply and waste water issues, District heating connections, Power grid connection)
Task 8: The Least Cost Analysis of Proposed Options
Task 9: Detailed Plan Cost Estimate of the Selected Alternative(s)
Task 10: Economic/Financial Evaluation of the Selected Alternatives
Task 11: Environmental and Social Impact Due Diligence
Task 12: Financing Options Review

Note: CLIN – Contract Line Item Number

The approach taken by Worley during the implementation of the CLIN01 Conceptualization scope of work considered the first six tasks as described below.

TASK 1: ASSESSMENT OF EXISTING CHPS AND RELATED DH FACILITIES

The study requires a good understanding of the conditions of existing CHPs, short- or long-term plans for their maintenance, rehabilitation and/or decommissioning, and the level of necessary investment for continuing operation.

Under this task, a high-level assessment of the existing CET-1, CET-2, CT Vest, CT Sud, and CT East plants was performed, including an assessment for the district heating related equipment located within plant boundaries. The assessment includes site / plant walkdown, interviews with management and operators, review of available existing reports, operational data, certifications, and other available documents in order to determine the current conditions of plant equipment and expected remaining operational lifetime. In addition, a rough estimate of required investment necessary for continuing safe operation of the plant and reliable heat and power supply is provided.

Data collected and used for the condition evaluation include operational characteristics, such as efficiencies of equipment, plant operating parameters, system capacity availability, O&M costs, heat and power sales, recent investment and other data needed.

Based on the data obtained during execution of the work, Worley summarized the findings and developed several scenarios with available options for refurbishment of the equipment for:

- minimum investment necessary for continuous operation till the new capacity is commissioned and
- necessary investment to prolong/expand the operation of CHP also to work in parallel with the new generating capacity.

TASK 2: HEAT AND ELECTRICITY DEMAND AND SUPPLY

Under this task, Worley gathered information on the historical and current Chisinau District Heating system heat load covered by the existing CHPs and local boilers supplying heat to the common DH network. Considering the impact of the potential change of the customer base, energy efficiency improvement in the DH system and in the user side, Worley developed the heat load forecast and the heat Load Duration Curve (LDC).

For the electrical load assessment, Worley gathered and summarized information on the historical and current electricity demand of Moldova by sectors, load characteristic, seasonal and hourly profiles, base and peak loads, and developed a forecast of load development, factoring the impact of consumer base changes, energy efficiency impact and the relevant conditions.

On the supply side, Worley gathered and evaluated information on power imports, and power generation by all sources, their availability, planned and unplanned outages based on historical data also considering the near-term plans to implement new power supply sources, including an asynchronous connection with the ENTSO-E system. This provides information on current and anticipated demand and supply situation in the energy sector and identifies the gaps between the supply and demand.

TASK 3: GAS AND WATER SUPPLY

For this task Worley gathered and summarized available information on current and forecasted gas supply availability, including from potential sources, and provide a summary of historical gas consumption, separately for all user categories in Moldova.

Based on confirmed information, Worley determined the availability of gas quantities in seasonal high and low demand regimes, gas pressures available for power generation, and any required/considered technical improvements to the gas supply network. As part of this task, Worley provides a summary of potential risks with gas supply availability, with the acceptable level of certainty.

In addition, Worley assessed the availability, reliability and quantity of technical water for the new power generating capacity, considering all reasonably available sources, technologies and storage capacity, as well as the need for water supply system improvements and estimated the required investments.

TASK 4: LAND AND STRUCTURAL ISSUES

Although determination of the final construction site is not expected to result from this conceptualization study, for this task Worley identified possible suitable locations considering proximity and availability of the required utility connections – electricity, heat, gas and water, any potentially usable structures or facilities, and any other issues which may need to be considered for final site selection. Only locations with all required conditions are listed, properly described and preliminary ranked based on their properties and available information.

TASK 5: LEGAL AND REGULATORY CONSIDERATION

The Worley team through Deloitte reviewed the relevant Moldova and EU legal and regulatory documents related to the construction and operation of large fossil heat and power generation plants, and, as part of Task 5 of the report, provide a summary of legal and regulatory issues to be addressed during the next phase of the feasibility assessment, planning, procurement and construction process.

The summary includes environmental issues, licensing, and the certification process required by the current Moldovan law and as required by the EU directives.

Worley summarized the results of the legal and regulatory considerations in the report, highlighting the required steps for achieving compliance with all legal and regulatory requirements. Potential roadblocks or substantial difficulties affecting the implementation was provided and properly apprised.

TASK 6: TECHNOLOGY OPTIONS

Based on findings of the previous tasks, for this task, Worley developed a list and description of applicable options of power, or heat and power generation technologies available and suitable for the activity, including equipment arrangement and configuration, system capacity, preliminary estimates of CAPEX, OPEX, efficiency and environmental consideration, and other technical and economic parameters. The options include the best available technology (BAT) in gas fired power or heat and power generation technologies, equipment configuration, generation capacity sizes and system operating parameters, as applicable.

Options were ranked based on their performance parameters, and best fit for the application in Moldovan conditions. A set of the best options is recommended for further evaluation during next project phase.

2.2.1 DATA INFORMATION REQUEST

Worley team efforts were closely coordinated with the USAID, the Government of Moldova and other stakeholders, e.g. ÎS Moldelectrica, SA Termoelectrica, SA Moldovagaz, etc. and their valuable input was considered during the development of this study.

A Data Request package was prepared by the Worley Team to organize the effort of information gathering for the analysis of options. The formal Data Request containing requests for all information that is anticipated from Moldavian sources was transmitted to the following project stakeholders in Moldova prior to the Kickoff meeting.

- Moldovagaz / Moldovatransgaz
- Vestmoldtransgaz
- ANRE
- Termoelectrica
- Moldelectrica
- CET Nord

2.2.2 SITE VISIT

An in-country kickoff meeting and meetings with the following project stakeholders in Moldova were conducted to introduce the project and discuss the required information.

- USAID

- Ministry of Economy and Infrastructure
- Moldova Energy Efficiency Agency
- Moldovagaz / Moldovatransgaz
- Vestmoldtransgaz
- ANRE
- Termoelectrica
- Moldelectrica
- CET-1, CET-2 and CET-Nord
- RED-Nord

Drafts of the each of the task sections were submitted for review by the USAID and Moldovan stakeholders. Information provided by the stakeholders and their comments have been incorporated in this report.

2.2.3 PROJECT TEAM

Project team composition is as follows:

- Worley USA
- Worley Bulgaria
- Deloitte Romania
- Institute of Power Engineering of Moldova

2.3 BACKGROUND INFORMATION

2.3.1 CLIMATE

The Republic of Moldova is a landlocked country in Eastern Europe, bordered by Romania in the west and Ukraine to the north, east and south. The capital is Chisinau. Moldova occupies an area of approx. 34,000 km^2. Its climate is temperate continental, characterized by a relatively short winter and a long hot summer.

The annual average temperature in Chisinau is +9.1°C. Negative temperatures usually start at the end of October and may last until the mid of April. Daily temperature range fluctuates by 5 – 10ºC. During the coldest month the relative humidity of the air is 78%.

The period with 0°C and below temperature consists of 81 days, while the heating period is considered as 166 days. During a normal winter, the temperature falls below 0°C for 60 – 70 days. The design temperature is –16°C. The summer period when the average temperature is above 15°C lasts for 120 – 140 days per year.

2.3.2 OVERVIEW OF COUNTRY'S ENERGY INFRASTRUCTURE

The Republic of Moldova shares borders with Romania to the west, and with Ukraine to the north and east. However, their electric power systems don't work in parallel till present.

Currently, the limited power generation capacity in the right bank is an issue for the country. Its annual electricity consumption is 4,270 GWh in average for the period from 2013 to 2017, peaked at 784 MW in 2017 (excluding the left bank). Out of the country's electricity demand, only around 20% has been covered by domestic generation sources located on the right bank of Dniester river including three Combined Heat and Power (CHP) plants and one run-of-river Hydro Power Plant (HPP).

The CHP plants are constrained for electricity generation as they are dispatched primarily to meet the heat load. The country's renewable development has been limited so far with installed capacities of 2.8 MW for solar and 24 MW for wind as of August 2018, which cannot be immediately expected as a major generation source for the near future. The remaining electricity demand for the right bank is covered by two external sources: Kuchurgan power plant or Moldavskaya GRES (MGRES) located in the left bank and power supply from Ukraine. MGRES was commissioned in 1964 and is operated by a subsidiary of Inter RAO UES.

Information on Moldova electricity supply balances in GWh for the period from 2013 to 2017 is provided in Exhibit 28 [5].

Exhibit 28: Moldova Electricity Supply Balances (GWh) for the period 2013 - 2017

Sources		2013	2014	2015	2016	2017	5 years average
Supply	CHP-1	59.5	67.4	47.2	43.9	32.4	50.1
	CHP-2	694.8	702.3	732.2	708.3	692.8	706.1
	CHP-Nord	60.2	61.5	66.6	67.5	60.3	63.2
	HPP Costesti	45.3	59.3	50.6	39.3	47.6	48.4
	Others	35.6	58.2	35.8	39.4	46.3	43.1
	HPP Dubasari	268.4	261.2	218.1	190.9	237.1	235.1
	MGRES	3044.5	3893.0	4610.4	4468.4	3557.2	3914.7
	Import from Ukraine	1455.7	730.7	17.6	3.7	1133.1	668.2
Demand	Right Bank	4230.2	4290.3	4289	4246	4295	4270.1
	Left Bank	1350.9	1543.3	1486	1316	1514	1442.0
	Export to Romania	82.9	0	0	0	0	16.6
Total		**5664**	**5833.6**	**5778.5**	**5562.4**	**5806.8**	**5728.9**

Transmission network is integrated with Ukraine and UPS/IPS. Moldova's transmission network consists of 5,977.6 km of transmission lines at three primary voltage levels: 400, 330, and 110 kV, operated synchronously with the former Soviet Union's United Power System / Integrated Power System (UPS/IPS). Moldova and Ukraine's transmission networks were designed, built and operated as an integrated system during the Soviet era. They are still operated as a one interconnected power system. Interconnections with Ukrainian power system include 11 lines of 110 kV and seven lines of 330 kV: one 330 kV line from Balti substation to Dnistrovska HPP of Ukraine, two 330 kV lines from Ribnita substation to Kotovsc substation of Ukraine, and four 330 kV lines from MGRES power plant to three substations in Ukraine.

Transmission capacity of all electrical transmission lines that interconnect the electric power systems of Ukraine and Moldova amounts to 700 MW due to some technical constraints. Transmission capacity of the mentioned links is limited during the peak load demand, if one of the lines is out of service.

Power system balancing, and frequency regulation are conducted by Ukrenergo's dispatch center in Kiev, which in turn depends on Russia for the frequency control.

Moldova transmission network can be connected to the Romanian grid only in an island mode. Romania is part of the European power system comprising several member transmission system operators (TSOs) which are organized in the European Network Transmission System Operators for Electricity (ENTSO-E). Currently, Moldova is not synchronized with the Romanian power system. Only three isolated 110 kV transmission lines are connected to part of the Romanian system for local power supply. One single circuit 400 kV line from Moldova's Vulcanesti substation to Romania's Isaccea substation physically exists but it remains disconnected at the Vulcanesti substation.

3 TASK 1: ASSESSMENT OF EXISTING CHPS AND RELATED DH FACILITIES

This section provides the results of a high-level assessment of the existing CET-1, CET-2, CT Vest, CT Sud, and CT East plants, including an assessment for the district heating related equipment located within plant boundaries. Based on the data obtained during execution of the work, several scenarios are developed that summarize:

- minimum investment necessary for continuous operation till the new capacity is commissioned and
- necessary investment to prolong/expand the operation of CHP also to work in parallel with the new generating capacity.

3.1 TERMOELECTRICA HEAT AND POWER GENERATION FACILITIES

The beginning of the district heating system in the city of Chisinau dates to 1946 with the creation of the first technical project of heat supply in Chisinau through the production of heat and electricity in a cogeneration mode. The first Chisinau Thermal Power Plant (CET-1) was commissioned in September 1951. Due to the difficult terrain (Chisinau is located on seven hills) the heating network was designed divided into independent hydraulic zones, which led to the construction of 17 pumping stations. The total length of main heating distribution pipelines is 269 km, the length regional distribution networks is 260 km. The length of the networks supplying domestic hot water to residential buildings is180 km.

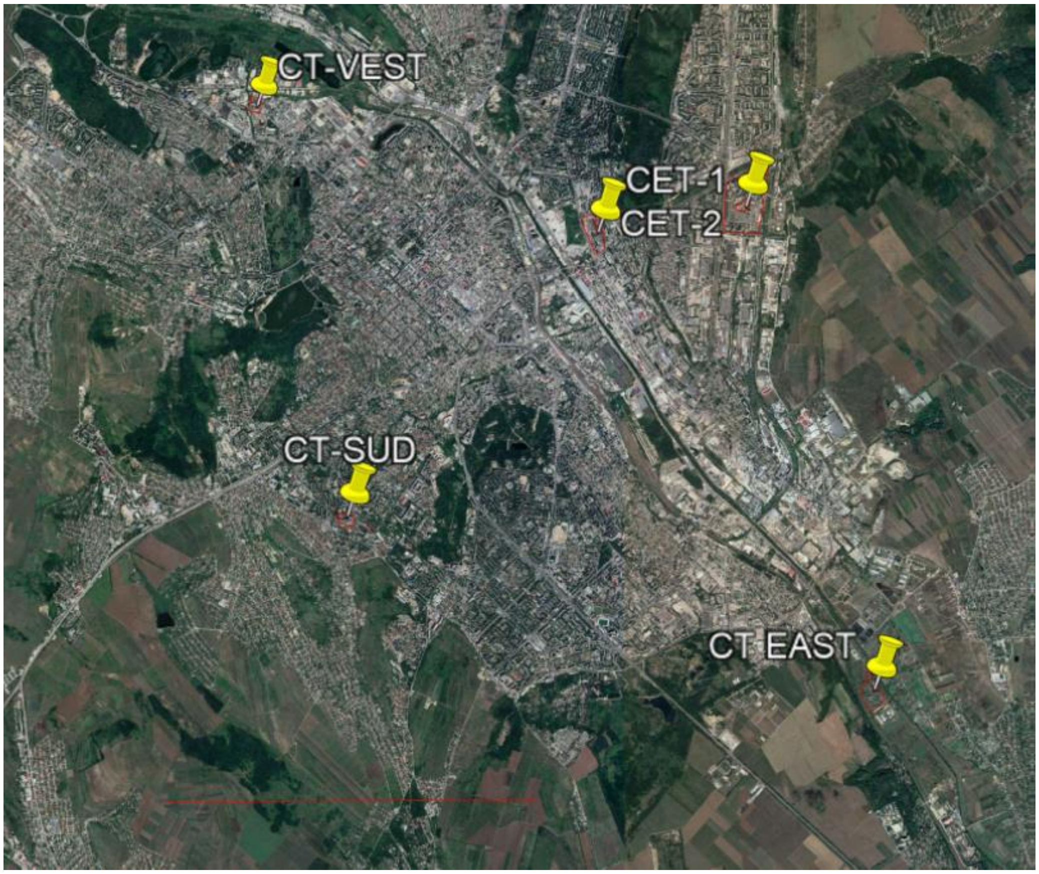
1976 was marked by the commissioning of the second combined heat and power plant (further named CET-2) and the heating network with a diameter of 1000 mm, which connected CET-1 and CET- 2 from Pump Station No. 8. CET-2 became the largest thermal power station in Chisinau upon commissioning of its 3 power units with total installed power capacity of 240 MWe and a heat capacity of 1,200 Gcal/h.

Since 1990, the Centralized Heating System of the city of Chisinau was managed by the Joint-Stock Company “Termocom”. In 2015, as a result of bankruptcy proceedings, a new company JSC Termoelectrica was established. Termoelectrica is a holding company composed of CET-1, CET-2 and Termocom (heat distribution and supply). Thus, JSC “Termoelectrica” has become the main producer of electricity in cogeneration mode, and heat producer and supplier in Chisinau and its suburbs.

Termoelectrica also operates two heating plants located in the Chisinau municipality: CT-SUD, CT-VEST, and nineteen (19) heating plants located in the Chisinau suburbs.

Approximate location of the Chisinau DH system major generating facilities is presented in Exhibit 29.

Exhibit 29: Termoelectrica power and heat generation facilities



3.2 CENTRAL HEAT AND POWER PLANT CET-2

CET-2 is the newest combined heat and power (CHP) generation station in Chisinau. It is designated by Termoelectrica as CHP Source 1. The plant was constructed between 1974 and 1982. The primary fuel is natural gas. The plant can also operate using heavy fuel oil, or a combination of gas and heavy fuel oil.

CET-2 is in the North-East suburb of Chisinau. The plant is adjacent to the Industrial Zone, where major industrial, construction and other enterprises of Chisinau are concentrated.

An aerial image of the CET-2 facility is presented in Exhibit 30.

Exhibit 30: Chisinau CET-2 Plant

The area occupied by CET-2 is 48.25 ha, out of these 32 ha are used by the operating facility at present. An area to the north-east of the plant (outside the plant boundary) has been allocated for future plant expansion.

The site elevation varies between 84 m and 90 m above sea level. The site water table is at 1 - 4 m, or 84.1 - 86 m above sea level. The foundations of the existing buildings range between 8 m and 11 m in depth.

The main customer for electricity is the local electricity distribution company, Union Fenosa, however, CET-2 supplies electricity to all 5 of the Moldovan distribution companies. CET-2 supplies heat to the residential sector of Budesti, Riscani, and Cecanii Noi and to others by the connection pipes with CET-1. Over the years CET-2 lost most of its industrial steam consumers.

3.2.1 CET-2 PLANT PERFORMANCE & OPERATION MODES

CET-2 consists of three operational natural gas fired CHP units and five natural gas fired Heat-Only-Boilers (HOBs) of which two are in operation. The CHP units have reached or are about to reach their permitted operational lifetime and therefore, they need to be renovated and/or overhauled in the coming two years to be kept into operation.

The CHP units are independent meaning that the boilers of different units cannot feed steam to the turbines of the other units.

The DH and power production capacities of the CHP CET-2 units, are 175 Gcal/h per unit and 80 MW_{gross} per unit, respectively. However, the total DH capacity of the three units is 375 Gcal/h, since the throughput capacity of the medium-low pressure part of the turbines is limited and the total heat exchanger capacity after the high-pressure parts is 75 Gcal/h. There are one common 75 Gcal/h high pressure steam heat exchanger for all units and three 100 Gcal/h low pressure steam heat exchangers (one for each unit).

The total capacities of the three units in two different operation modes are presented in Exhibit 31:

Exhibit 31: CET-2 Capacity and Main Technical Parameters

Parameter	**Unit**	**Mode 1**			**Mode 2**		
Gross Power	MWe	80	80	80	80	80	80
DH extraction	Gcal/h	100	100	100	100	100	100
IND extraction	Gcal/h	75	-	-	25	25	25
DH supply	Gcal/h	175	100	100	125	125	125
Life Steam	t/h	470	300	300	335	335	335
Fuel	Gcal/h	297	195	195	222	222	222

Note: Mode 1: One Unit at full load, two units at partial load
Mode 2: Each Unit at equal load

3.2.2 CET-2 DH PERFOMANCE IN RECENT YEARS

During 2018, CET-2 maximum heat load was 348 Gcal/h as DH hot water, and net maximum electric power load was 206 MWe. The plant available electric power capacity when operating in condensing mode is limited by the size of the steam condensers, designed for a maximum condensing steam rate of 220 t/h with an optimum cooling water temperature of 20°C. Since the process steam load is very low, the maximum electric power output of the plant depends on the District Heating load. CET-2 maximum electric power capacity when operating in condensing mode is 160 MWe (2×80 MWe), which is limited by the cooling water flow rate of 5,000 m^3/h per steam turbine.

During the colder months, with a sufficient district heating load, the plant output is not technically restricted, and it can theoretically operate at full load. The total available capacity and thermal load requirements to achieve nominal power output are presented in Exhibit 32.

Exhibit 32: CET-2 Total Available Capacity, full load with HOB 1&2

Parameter	**Units**	**Mode 1**	**Mode 2**
Gross Power	MWe	240	240
DH extraction	Gcal/h	300	300
IND extraction	Gcal/h	75	75
DH ST supply	Gcal/h	375	300

Parameter	Units	Mode 1	Mode 2
HOB 1&2	Gcal/h	200	200
DH Total	Gcal/h	575	575
Live Steam	t/h	1,070	1,005
Fuel	Gcal/h	904	883

The plant reported heat rates (Exhibit 33) for the different operating modes are expressed in Grams of Reference Fuel (grf) per kWh of generated power, and kilogram of reference fuel (kgrf) per Gcal of heat produced. Reference fuel is defined as a hypothetical fuel with a lower heating value (LHV) of 7,000 kcal/kg.

Exhibit 33: CET-2 Reported Heat Rates

Parameter	Gross Heat Rate, grf/kWh	Gross Efficiency, %
Electric power in DH mode	200	61
Electric Power in condensing mode	340	35
Heat, kgrf/Gcal	173	96

The CET-2 auxiliary power loads are reported at approximately 12% of the gross generated power, with 5% attributed to electric power generation and 7% attributed to heat production.

Operational data for the period of 2012 to 2018 (excluding 2016) is presented in Exhibit 34 [6].

Exhibit 34: CET-2 operating data for 2012 - 2018

Parameter	Units	2012	2013	2014	2015	2016	2017	2018	AVERAGE
		Annual	Annual	Annual	Annual	Annual	Annual	Annual	2012-18
Installed power of electric generators	MW	240	240	240	240	240	240	240	240
Available power of electric generators	MW	136	131	126	126	209	109	106	135
Thermal power installed	Gcal/h	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200
Available thermal power	Gcal/h	404	416	427	427	504	291	356	404

Parameter	Units	2012	2013	2014	2015	2016	2017	2018	AVERAGE
		Annual	Annual	Annual	Annual	Annual	Annual	Annual	2012-18
Maximum electrical load	MW	232	195	228	228	214	231	218	221
Maximum thermal load	Gcal/h	378	307	364	319	318	389	357	347
Heating degree-days		3,004	3,412	2,884	3,435	3,577	2,854	3,240	3,201
Amount of electricity produced	mil. kWh	743	695	702	732	708	693	725	714
Amount of electricity delivered	mil. kWh	637	594	601	627	608	597	626	613
Amount of heat supplied to DH system	Gcal	1,135,661	1,047,469	1,049,748	1,095,804	1,137,625	1,110,243	1,156,659	1,104,744
Efficiency of power plant to produce energy	%	72	72	71	76	73	78	78	74
Fuel used to produce energy (conventional)	mil tcc	334	310	314	322	323	312	327	320
Amount of CO_2 emitted into atmosphere	mil tons	541	502	508	522	524	505	530	519
Power generation based on Heat supply	MWhe/Gcal	0.65	0.66	0.67	0.67	0.62	0.62	0.63	0.65
In house power demand	%	14.30%	14.50%	14.40%	14.30%	14.20%	13.90%	13.70%	14.20%
Amount of heat supplied to DH system	MWht	1,320,536	1,217,987	1,220,637	1,274,191	1,322,820	1,290,980	1,344,952	1,284,586
Amount of electricity delivered	MWhe	742,898	694,760	702,326	731,578	708,334	692,828	725,224	713,993
Heat generation operating hours	hours	2,811	2,518	2,458	2,566	2,257	3,815	3,249	2,737

3.2.3 MAJOR EQUIPMENT AND SYSTEMS

The key technical parameters and information related to major equipment and mechanical systems is presented below [7].

STEAM BOILERS

The steam boilers are reported to be in a relatively satisfactory condition and appear to be properly maintained. To date the boilers lifetime hours in operation are slightly above 200,000 hours, Unit 1 accumulated above 220,000 h, and approached its Fleet Service Life limit as discussed in the following sections of this report. Steam Boilers design characteristics are presented in Exhibit 35.

Exhibit 35: CET-2 Steam Boiler Design Characteristics

Steam Boiler Equipment (3 Units)	Characteristics	
	Natural Gas	Heavy Fuel Oil
Type	TGM-96B	
Productivity	480 t/h each	
Main Steam Pressure	140 ata	
Main Steam Temperature	540 °C	
Feedwater Temperature	230 °C	
Number of Burners	4	
Efficiency	93.38%	93.5%
Design Fuel	Natural Gas	Heavy Fuel Oil
Design Fuel Flow	32,240 m³/h	31,600 kg/h
Stack Flue Gas Temperature (design/actual)	125 °C (138 °C)	151 °C (161°C)
Note: The design fuel is natural gas with LHV 8,300 Kcal/kg or HFO with LHV of 9,300 Kcal/kg		

CET-2 HOT WATER BOILERS

Three natural gas / HFO fired HW PTVM boilers (B-1, B-2, and B-3) were commissioned in1974 and 1975. Boilers B-2 and B-3 are operational and boiler B-1 is not operational. The KVGM-180 boilers B-3 and B-4 are natural gas / HFO fired HW- boilers that were commissioned between 1987 and 1988 and have not been in operation since 1993. Major technical attributes of the HW boilers are presented in Exhibit 36.

Exhibit 36: CET-2 Hot Water Boiler Design Characteristics

Equipment	**Characteristics**	
	Natural Gas (3 Units)	Heavy Fuel Oil (2 Units)
Boiler Type	PTVM-100 (1,2&3)	KVGM-180 (4&5)
Manufacturer	Belogorod, Russia,	Barnaul, Russia
Capacity, Gcal/h	100	180
Water Pressure, MPa	2.5	2.5
Water Flow, m³/h	800 - 2,235	4,420

Equipment	Characteristics			
Water Temperature, °C	70/150		70/150	
Number of Gas Burners, pc	16 (units 1, 2 and 3)		8 (units 4 and 5)	
Flue Gas Temperature, °C	245			
Design Fuel	Natural Gas	Heavy fuel oil	Natural Gas	Heavy Fuel Oil
Boiler Efficiency, %	91.0 - 93.51	89.5	89.5	90.9

Boilers B-1 and B-2 are reported to operate during the peak heat demand periods. During the 2016 heating season, Boiler B-1 was in operation for about two months. During the 2017 and 2018 heating seasons, Boiler B-1 was in operation for several days each. Boiler B-2 was in operation last time during the 2016 heating season for several days. As of the end of 2018, Boiler B-1 accumulated 31,664 lifetime operating hours, and Boiler B-2 accumulated a total of 23,729 operating hours [2].

FLUE GAS SYSTEM

Flue gas from the boilers is evacuated via the 180 m-tall operating stack, which has diameter of 7.2 m. Another stack, which is not in operation, is 240 m high and 9.6 m in diameter. It was intended for an abandoned expansion project, and it is about 80% complete.

The 180 m stack currently in operation has sufficient throughput and buoyancy for the three existing units and two stand-by HWB-boilers.

FUEL HANDLING SYSTEM

CET-2 utilizes natural and gas as a main fuel and heavy fuel oil as a back-up fuel. Summary of characteristics for both fuels is presented in Exhibit 37.

Exhibit 37: Fuel Characteristics

Parameter	Natural Gas	Heavy Fuel Oil
Heating Value (LHV), kcal/kg	7,945	9,602
Specific Density, g/dm^3	0.686	0.947
Moisture, %	NA	6.7
Sulfur, %	NA	2 % (up to 3%)
Ash, %	NA	0.039

The natural gas pipeline is designed for the maximum supply pressure of 6 Barg with corresponding maximum flow rate of 300,000 m3. It is operating at 3 Barg (maximum corresponding flow rate of 150,000 m3) due to the regulation for the maximum natural gas pressure within the city limits. There is single pressure regulating and metering station on site designed for 6 Barg. During the winter peak gas consumption, natural gas pressure is reported to drop to 1 Barg. CET-2 consumes 90,000 m3/h of natural gas at maximum load, (e.g. minimum ambient temperature). Its average gas consumption is about 60 000m3/h. The plant natural gas battery limit is at the pressure regulation station located inside the CET-2 fence.

DH WATER CIRCULATION PUMPS

The DH water circulation pumps are divided into two pump groups. Their key technical information is presented in Exhibit 38.

Exhibit 38: DH Water Circulation Pumps Data

Pump Group	Q-Ty	Model	Capacity, M^3/H X dP Bar	Electric Drive / Unit, Kw	Total Capacity, M^3/H
1	4	CЭ (SE)-5000 x 50	5,000 x 5	1,000	25,000
2	6	CЭ (SE)-1250 x 140	1,250 x 14	600	7,500
	3	CЭ (SE)-5000 x 160	5,000 x16	1,100	15,000
	3	CЭ (SE)-2500 x 180	2,500 x 18	1,500	7,500

STEAM TURBINES AND GENERATORS

The three extraction/condensing design steam turbines model PT-80/100-130/13 are of a two-stage design with two regulating steam extractions. Each turbine is connected to one boiler. The turbines are directly connected to the electric generators model TVF-120-2 with a capacity of 125 MVA each. There is no steam cross connections between the three turbines. Steam turbine main technical information is presented in Exhibit 39.

Exhibit 39: Steam Turbines and Electric Generators Data

Equipment	Characteristic
Steam Turbine, units	3
Manufacturer	LMZ, St. Petersburg, Russia
Nominal Capacity, MW	80 (Max. 100) (Note a)
Model	PT-80/100-130/13
Throttle Steam Flow, t/h	470
Throttle Pressure, kg/cm^2	130
Throttle Temperature, °C	525
Process Steam Extraction, kg/cm^2	13±3
Process Steam Extraction Flow Rate, t/h	185 - 265 t/h max; (Note b)
District Heating Extractions, kg/cm2	0.5 - 2.5; 0.3 - 1.0[c]

Equipment	Characteristic
District Heating Extractions Flow rate, t/h	132 t/h (150 t/h max; Note c)
Condenser	
Type	80 KYC
Steam Capacity, t/h	217
Pressure, kg/cm^2	0.035
Circulating Water Flow, m^3/h	8,000
Generator	
Type	TVF-120-2
Capacity, MVA	120
Notes: a. Achievable at certain combination of process and district heating extractions flow rate b. Maximum process steam extraction with no district heating extraction c. Maximum district heating extraction with no process steam extraction	

Metallurgy assessments of the high pressure and temperature parts are periodically conducted by an authorized assessment company. Based on their recommendations, superheated steam temperature was decreased from 555°C to 530°C, on units 1 and 2, when they reached 125,000 hours of operation.

COOLING SYSTEM

Each steam turbine is equipped with a steam condenser. The steam condensers are fitted with brass tubes, and designed for circulating water flow of 8,000 m3/h. The condensers are reported to be in a good condition. The condensers are cooled by circulating water which in turn is cooled by two cooling towers (common for the three turbines). The cooling towers are of the counter-flow type, natural draft. Main technical information is presented in Exhibit 40.

Exhibit 40: Cooling Tower Design Data

Parameter	Value
Quantity	2
Type of the tower	Counter-Flow, Natural draft
Design Thermal load (MWt)	156.6 (actual not reported)
Design range	Δt 9°C
Circulating water per both	260,870 m^3/day, 95,224,000 m^3/y

The cooling system capacity is 156.6 MWt, or approximately 70% of the required for 100% operation of the three units in condensing mode. The condenser design cooling load demand is estimated at 75 MWt per unit, or 225 MWt for the plant.

WATER TREATMENT SYSTEM

The water treatment system at CET-2 includes the following processes:

- Raw water pre-treatment system, including two clarifiers for lime-soda softening and coagulation, with a total capacity of 70 m^3/h.
- District heating network make up water system, based on two-stage Na-cation exchange, including main system with capacity 250 m^3/h, and a back-up system of 150 m^3/h.
- Demineralization system with capacity 200 m^3/h, based on a four-bed process.
- Returning condense oil removal system, based on [mechanical filter]→[activated coal filter]→[Na-cation] process, with a capacity of 40 m^3/h.
- Regeneration of backwash water, including four 400 m^3 regeneration tanks, lime and chlorine mixers, two filter-presses (FPAKM), and pumps.
- Waste water treatment system.

CET-2 water treatment performance data is presented in Exhibit 41.

Exhibit 41: Water treatment system performance

Water Type	Consumption
Demineralized water, including for plant needs (15%)	383,387 m^3 57,508 m^3
Chemically treated water, including for plant needs (10%)	1,892,820 m^3 189,282 m^3

PLANT HIGH VOLTAGE ELECTRICAL SYSTEM

CET-2 is connected to Moldelectrica 330kV Straseni substation via 25 km of 3x110 kV lines, owned by GasNatural Fenosa. A previous study established that the existing 110 kV lines can accommodate ~100 MW of additional generation at the CET-2 site. The high voltage substation on CET-2 site is owned by CET-2. The substation isophase bar has 2 available sections for additional circuit breakers.

GENERATORS

The generators of type TVF-120 2U3 are manufactured by Elektro-Power, St. Petersburg, Russia and installed in 1976, 1978 and 1980. They are hydrogen-cooled by the water to hydrogen heat exchangers. The nominal capacity is 120 MVA / 133 MW at a cos (φ)) = 0,8 and the nominal efficiency is 98.4%. Their condition is reported as good.

TRANSFORMERS

Each of the three generators is connected to a 125 MVA two winding Generator Step-up Transformer (110-10 kV) and a 25 MVA three winding Unit Auxiliary Transformer (10-6/6 kV). Generator Step-up Transformers 1T and 2T are connected to 110 kV Bus Section A. Generator Step-up Transformer 3T is connected to 110 kV Bus Section B. Each of the generator tied Unit Auxiliary Transformers 21T, 22T and 23T, powers a 6 kV Unit Auxiliary sectionalizing bus. Each of the Unit Auxiliary Transformers is provided with an on-load tap changer.

Two Station Auxiliary Transformers 20T (110-6/6 kV), 32 MVA and 30T 110-6/6 kV), 40 MVA are connected to the 110 kV buses and 6 kV Unit Auxiliary buses. A summary of the transformers technical data is presented in Exhibit 42.

Exhibit 42: Transformer Data

Model	Capacity, kVA	Voltage, kV	Installed	Station Number
TRDN-32000 110/6/6	32,000	115	1976	20T
TDTs-125000 110/10	125,000	121	1989	1T
TRDNS25000 10/6/6	25,000	10.5	1976	21T
TDTs-125000 110/10	125,000	121	1986	2T
TRDNS25000 10/6/6	25,000	10.5	1978	22T
TDTs-125000 110/10	125,000	121	1980	3T
TRDNS25000 10/6/6	25,000	10.5	1980	23T
TRNDTsN40000 25000/110/ 6.6/6.6	40,000/ 25,000	115	1989	30T

PLANT CONTROL SYSTEM

Electric power grid and district heating dispatch orders are received in the main plant control room. The main control room is operated by the plant shift supervisor. The main room controls 110 kV switch gear, 6 kV in-house switches and the fire protection system. Units 1, 2 and 3 control panels are in the same control room. Most of the equipment is controlled manually. Control rooms are equipped with monitoring equipment.

Metering installed at CET-2 includes measurement and recording of electricity, steam and heat supply. Natural gas and HFO flows are measured and used for calculation of the plant performance.

3.2.4 MAINTENANCE

The efficiency of the plant (boiler, balance of plant and turbine) is achieved by maintenance measures directed at reduction of losses, vacuum leaks and air leaks in the furnace; keeping in condition valves, burners upgrades, good housekeeping, etc.

The general condition of the plant is reported satisfactory. All equipment failures are registered and reviewed. Each year, a survey of major equipment is carried out to identify required maintenance work, and a list of tasks to be carried out is prepared.

CET-2 typical maintenance schedule is:

- Major overhaul: every 4 years
- Intermediate overhaul: every 2 years (if required)
- Ongoing maintenance: once a year

The controlling agency is Technical Inspection (Technadzor) of the Ministry of Economics, which oversees licensing of high-pressure piping and high-pressure boilers, but not steam turbines. For the steam turbines, CET-2 utilizes OEM recommendations.

In 2019, CET-2, Unit 1 is scheduled to undergo major rehabilitation and modernization to renew its operating license, while Unit 2 is scheduled for a major overhaul in 2021, and Unit-3 in 2024.

ENVIRONMENTAL REQUIREMENTS AND, PERFORMANCE

SA Termoelectrica reported the CO_2 emissions at 0.23 tCO_2/Gcal of consumed fuel. Annual CO_2 emissions are reported at 150,000 – 160,000 tonnes of CO_2.

SOIL CONTAMINATION AND ASBESTOS ISSUE

No specific soil contamination has been reported by Thermoelectrica and observed during Worley's site visit. Due to the vintage of the plant design, asbestos is likely present, which could add costs to the projects on site.

SECURITY OF POWER SUPPLY

According to Moldelectrica no specific problems with the HV grid have been reported.

3.2.5 CENTRAL HEAT AND POWER PLANT CET-1

CHP CET-1 is designated by Termoelectrica as Source 2. Its major equipment include eight (8) natural gas fired steam boilers and five (5) steam turbines. Four of the boilers and two of the turbines are in operation only during off heating season.

CET-1 is located in the north-eastern part of the central Chisinau. Among all heat producers in the city the plant is the closest to the city center. CET-1 facilities include approximately thirty buildings with a total building area of 20,748 m^2, located on 14 ha. Other companies for repair and supply of related equipment are located on CET-1 premises. The plant was constructed in three stages beginning in 1951, with most of the existing units commissioned by 1961. The plant was initially constructed for coal firing. During 1966-69 all boilers were converted from coal firing to natural gas firing. as a main fuel, with HFO as a back-up fuel.

Aerial image of the CET-1 facility is presented in Exhibit 43 and information about the plant installed capacity is presented in Exhibit 44.

Exhibit 43: Chisinau CET-1 Plant Location

Exhibit 44: CET-1 Installed Capacity

Electric Power	54 MW
Heat (from the turbines)	194 Gcal/h
Water heating boilers	200 Gcal/h
Steam boilers	540 t/h

CET-1 OPERATING DATA

CET-1 cannot operate without the district heating load or steam supply load to the industries in the area. The highest historical annual operating hours for CET-1 were at 8,040, with 720 hours being shut down due to district heating annual summer outage.

CET-1 follows the district heating load by varying the supply temperature at almost constant water flow rate during the heating season. Historical peak hot water supply temperature is 119°C. Steam for the base load district heating heaters is provided from the exhaust of the steam turbines TG1, TG4 and TG5. Exhibit 45 presents the typical modes of operation.

Exhibit 45: CET-1 Typical Modes of Operation

Equipment with Corresponding Auxiliaries in Operation	District Heating Flow Rate, m³/h	8-13 Barg Process Steam Load, t/h
Typical winter mode of operation – 3,984 hours		
Four or five IP boilers (B1 - B6)	5,000 - 7,000	35 - 60
Both HP boilers B7 and B8		
All turbines TG1, TG4, TG5 and TG6		
Typical summer mode of operation – 4,056 h		
One or two IP boilers (B1 - B6)	2,000 - 3,000	20 - 40
Turbine TG4		

The plant has steam headers interconnecting the inlets and outlets of the boilers and turbines, allowing for operation of any combination of boilers and turbines. The DH-water in the return line is heated first by heat exchangers with extraction and back-pressure steam. The plant uses hot water boilers B9 and B10 as peaking units after the heat exchangers.

Plant annual performance data for the period of 2012 to 2018 (excluding 2016) [8] is presented in Exhibit 46.

Exhibit 46: CHP CET-1 Annual operating data

Parameter	Units	2012	2013	2014	2015	2016	2017	2018
Installed power of the electric generators	MW	66	66	66	66	n.a.	66	66
Available power of electric generators	MW	66	66	66	66	n.a.	20	34
Thermal capacity installed	Gcal/h	239	239	239	239	n.a.	239	239
Available thermal capacity	Gcal/h	239	239	239	239	n.a.	35	91
Maximum electrical load	MW	32	28	27	27	n.a.	8	10
Maximum thermal load	Gcal/h	91	79	71	71	n.a.	37	43
Amount of electricity produced	mil. kWh	57	59	67	47	n.a.	12	36
Amount of electricity delivered	mil. kWh	48	50	56	39	n.a.	8	27
Amount of heat supplied to the collectors	Gcal	184,661	170,949	167,793	136,384	n.a.	57,190	160,618

Parameter	Units	2012	2013	2014	2015	2016	2017	2018
Efficiency of power plant to produce energy	%	85	83	77	84	n.a.	92	89
Fuel used to produce energy (conventional)	mil tcc	39	38	42	30	n.a.	11	31
Amount of carbon dioxide emitted into the atmosphere	mil tons	63	62	68	49	n.a.	17	50
Power generation based on Heat supply	MWhe/ Gcal	0.31	0.35	0.4	0.35	n.a.	0.21	0.22
In house power demand	%	16.00	15.80	16.20	16.70	n.a.	32.50	25.20
Amount of heat supplied to the collectors	MWh th	214,722	198,778	195,108	158,586	n.a.	66,500	186,765
Amount of electricity delivered	MWh e	56,708	59,479	67,387	47,200	n.a.	12,180	35,683
Heat generation operating hours	hours	773	715	702	571	n.a.	1,634	1,765

BOILERS

Technical characteristics of the CET-1 boilers are presented in Exhibit 47.

Exhibit 47: CET-1 Boiler Design Summary

Boiler Model	TC-35 (GM-50)	BKZ-120-100GM	PTVM-100
Manufacturer	Taganrog Boiler Works	Barnaul Boiler Plant	Dorogobuzh
Quantity	6	2	2
Station Number	Steam boilers B1-B6	Steam boilers B7-B 8	HW-boilers B9-B10
Commissioning Year	1951; 1954; 1955; 1958; 1959 (2 units)	1961	Not reported
Description	Single drum, natural circulation, bottom supported, initially coal-fired grate converted to gas/ HFO	Single drum, natural circulation, top-supported, gas/HFO fired	Tower type, hot water; peaking units
Capacity, T/H	50	120	100 Gcal/h
Pressure, Barg	39	92	
Temp., °C	440	520	75/150
No. Of Burners	4	8	16
Flue Gas Temp., °C	138 (gas)/ 155 (HFO)	135 (gas)/ 150 (HFO)	

Notes:

1. The boiler walls are of tube sealed by refractory design (not gas-tight membrane walls).
2. Air heaters of all boilers are of the tubular type.
3. The HW-boilers No. 9 and 10 have not been in operation since 1994.

Only boilers B1 through B4 (all model TC-35) are reported currently in operation during the off-heating season. These boilers accumulated lifetime operating hours ranging from 232,871 to 254,866 [2].

Condition of the operating CET-1 boilers is judged satisfactory for another approximately 5-8 years of operation, provided that good housekeeping and regular preventive maintenance measures are employed, The CET-1 boilers could continue operate as DH reserve and DHW service supplier during off heating season period.

FUEL HANDLING SYSTEM

CET-1 uses natural gas as a main fuel, and HFO as a back-up fuel.

Natural gas is delivered to Chisinau by a 75-Barg main line. Upon connection to the Chisinau distribution system, gas pressure is first reduced to 12 Barg and then to 3 Barg. CET-1 is connected to the 3-Barg distribution system by a 75 mm pipeline. The gas line comes to the plant pressure reducing and metering station, where gas is metered, filtered and its pressure is reduced to 0.5 Barg. Gas temperature, pressure and flow rate are recorded. The main equipment is installed in 1994. The natural gas has LHV of 7,968 kcal/ Nm^3. During the coldest month the gas supply is reported as not reliable.

HFO has LHV of 9,602 Kcal/kg, a moisture content of 1.5 % and Sulphur content of 1.60 %. HFO is delivered to the plant by railway. Steam lances are used for heating HFO in the railway tankers. 16 railway tankers can be unloaded at a time. The following equipment is used for HFO handling: a transfer tank at the railway; storage tanks with heating coils using steam to keep the required HFO viscosity; filtering equipment; HFO- heating and pumping system. The total storage capacity is about 16,000 m^3, sufficient for about one month of operation at a load of 30-40%. The unloading tank (concrete underground, V=3,500 m^3) and the storage tanks (3 x 5,000 m^3) are installed in 1997. The pumps are at least 30 years old. The condition of the total system is reported as satisfactory.

STEAM TURBINES AND GENERATORS

Technical characteristic of the steam turbine generators installed at CET-1 are presented in Exhibit 48.

Exhibit 48: CET-1 Steam Turbine-Generators Summary Data

Unit No.	**TG-1**	**TG-2**	**TG-4**	**TG-5**	**TG-6**
Model	R-12-35/3M	PT-12/15-35/10M	PR-10-35-1.2	R-27-90-1.2	R-5-90-37
Manufacturer (All in Russia)	Kaluga Turbine Plant	Kaluga Turbine Plant	Bryansk Machine Plant	UtMZ,	UtMZ
Commissioned Year	1994	2001 (modified)	1957	1960	1961
Type	Back pressure	Back pressure	Back pressure, with 0.8-1.3 MPa steam extraction	Back pressure; modified type VT-25-5 without LP section	Back pressure

Unit No.	TG-1	TG-2	TG-4	TG-5	TG-6
Capacity, MWe	12	12	10	27	5
Throttle Steam Pressure, Barg	35	35	35	90	90
Throttle Steam Temperature, °C	435	435	435	520	520
Steam Flow, T/H	93		115	155	105

While both TG-1 and TG-2 are reported operational, only TG-1 was in operation during the off-heating seasons of 2016, 2017, and 2018. Last time TG-2 is reported in operation was in 2016. As of the end of 2018, TG-1 has accumulated 36,940 lifetime operational hours, and TG-2 at total of 68,097 hours. All other steam turbines are currently not in operation [2].

DH-NETWORK PUMPS

In the network there are the following circulation pumps as presented in Exhibit 49.

Exhibit 49: DH-Network Pumps

Model	Q-Ty	Data
CЭ (SE) -1250 x 140	7	1,250 m^3/h, DP=14.0 bar, 630 kW

CONDENSERS AND COOLING SYSTEM

None of the operating CET-1 turbines is equipped with a condenser. Thus, total district heating and process steam load of 194 Gcal/h is required for the turbine generators to achieve their rated electric power capacity. CET-1 cooling towers have been dismantled. Two cooling ponds (1,000 m^3 each) are used for the cooling loads of turbine auxiliary equipment and water treatment plant, but the system is reported as unreliable.

WATER TREATMENT SYSTEM

CET-1 has a contract with "APA-Canal" JSC for the supply of water and the water treatment plant comprises the following facilities:

- Demineralization;
- Reagent storage and preparation;
- Tanks;
- Pre-treatment facility (commissioned in 1987);
- Waste treatment facility (commissioned in 1979);
- Central and express labs;

The major components of the water treatment plant were commissioned in May of 1973. All facilities above are reported to be in a satisfactory condition and their key technical information is presented in Exhibit 50.

Exhibit 50: Water Treatment Performance Data

WATER USES	Treated Water Flow Rate, m^3/h	
	DESIGN	ACTUAL
Pre-treatment	500	400
District Heating water make up	250	220
Demineralized water make up	150	120

PLANT ELECTRICAL SYSTEM

Electrical generation at CET-1 site is based on four (4) generators G1, G4, G5 and G6 connected to their respective steam turbines 1, 4, 5 and 6. All generators are air-cooled. Generators G1, G4 and G6 are connected to five (5) sections of 6.3 kV assembly buses which can be quickly switched from operation into reserve and back without interrupting power supply to customers. Power from generator G5 can be supplied to 110 kV external customers and to the plant auxiliary loads. The five sections of the assembly buses can supply power to 6 kV and 110 kV external customers and CET-1 auxiliary loads.

ELECTRIC GENERATORS DATA

Exhibit 51: CET-1 Electric Generators Data

Station Number	**G1**	**G4**	**G5**	**G6**
Capacity, MW	12	12	27	60
Model	T-12-2	T2-12-2	TBC-30	T2-6-2
Power Factor	0.8	0.8	0.9-0.95	0.8
Manufacturer	Lisva, Russia	Electromash, Kharkiv, Ukraine		
Installation Year	1994	1958	1960	1961
Year Last Repaired	1998	1999	1997	1996
Year Last Tested	1998	1999	1999	1999

The generators and their associated exciters are reported in relatively satisfactory condition. CET-1 switchyard includes distribution buses at 110 kV; 6.3 kV and 0.4 kV. The plant is also equipped with two DC storage batteries (CH-504).

TRANSFORMERS BASIC INFORMATION

Exhibit 52: CET-1 Transformers Basic Information

Station No.	Model	Capacity kVA	Voltage kV	Year Installed
1T	TDTG-15000/110	15,000	110/35/6.3	1954
2T	TDTG-15000/110	15,000	110/35/6.3	1956
3T	TDTG-40500	40,500	110/35/6.3	1969
20 units	Different types	Approx. 9 MVA	6.3/0.4	1951-1953

MAINTENANCE

The general appearance for a plant of this age is good (good housekeeping, cleanness, correct lighting, dismounted equipment stored in special areas, etc.). Within CET-1, there are many procedures that cover activities and tasks related to plant maintenance. Much of the CET-1 electrical equipment has been in operation for more than 40 years and needs extensive O&M effort to keep it operational.

ENVIRONMENTAL REQUIREMENTS AND, PERFORMANCE

SA Termoelectrica reported the CO_2 emissions at 0.23 tCO_2/Gcal of consumed fuel. Annual CO_2 emissions are reported at 7 000-13 000 tonnes of CO_2.

SOIL CONTAMINATION AND ASBESTOS ISSUE

No specific soil contamination has been reported by Thermoelectrica and observed during Worley's site visit. Due to the vintage of the plant design, asbestos is likely present, which could add costs to the projects on site.

SECURITY OF POWER SUPPLY

CET-1 is geographically located close to the power loads. According to Moldelectrica no specific problems with the HV grid have been reported.

3.2.6 OVERVIEW OF HOB PLANTS IN CHISINAU

Currently, Termoelectrica owns two operating heat generating plants located in Chisinau CT-Vest and CT-Sud, as well as 19 district heating plants located in the suburbs of Chisinau. All these heat sources consume natural gas, using fuel oil as a backup fuel. CT-East was indented to produce predominantly industrial steam and is currently not in operation. Their aerial views are presented in Exhibit 53, Exhibit 54, and Exhibit 55.

Exhibit 53: Chisinau CT-Vest Heat Boilers

Exhibit 54: Chisinau CT-Sud Heat Boilers

Exhibit 55: Chisinau CT-Est Heat Boilers

Key technical data for the three HOB plants is presented in Exhibit 56.

Exhibit 56: CT-Vest, CT-Sud, CT-Est Key Technical Data

Model	Quantity	Name Plate Capacity		Power Supply
		Per Unit	Total	
CT-Est				
KBGM-180, HOB	2	180 Gcal/h	360 Gcal/h	2 X 110 kV
PE-25/14 FM, STEAM	2	50 t/h	100 t/h	
CT-Vest				
PTBM-100, HOB	4	100 Gcal/h	400 Gcal/h	4 X 6 kV
DKBP-6,5/13, STEAM	2	6,5 t/h	13 t/h	
CT-Sud				
PTBM-30, HOB	2	30 Gcal/h	60 Gcal/h	4 X 6kV
IITBM-50, HOB	1	50 Gcal/h	50 Gcal/h	
PBTM-100, HOB	2	100 Gcal/h	200 Gcal/h	
DKRP-10/STEAM	1	10 t/h	7.0 t/h	

All boiler plants are equipped with HFO systems including: storage tanks with heating coils; filtering equipment; heating system before burning (HFO heaters); equipment for HFO supply to the boilers (HFO-pump station).

CT-EST EAST BOILER PLANT

CT-East (Vostochnaya) is located on the south-east side of the city. The plant area is 11,0 ha and the installed heat capacity is 360 Gcal/h. The boilers were installed 1992-1995. The installed water treatment capacity is 315 m3/h. HFO is supplied by the railroad. The storage capacity is: rail station tank (500 m³); storage tanks 3 x 5000 m³. CT-East is equipped with the DH network circulation pumps. Their key parameters are presented in Exhibit 57:

Exhibit 57: CT-Est Network Circulation Pumps

Type	Q-Ty	Data
CЭ-2500 x 180	3	2,500 m³/h, 18.0 bar, 1600 kW

Key technical data for the hot water boilers is presented in Exhibit 58.

Exhibit 58: CT-Est Hot Water Boilers Main Technical Data

Boiler Type	Qty	Heat Capacity	Pressure	Water Temperature, °C		Flue Gas Temp. °C	
		Gcal/Hr	Kg/cm²	Inlet	Outlet	Gas	Oil
KVGM-180	2	180	16	70	150	196	245
Steam boilers DE-50-14 GM	2	50 t/hr	13		Sat.	194	

CT-VEST BOILER PLANT

CT-Vest is located in the Buiucani district, in the North-West area of the City of Chisinau. The plant area is 2,772 ha and installed heat capacity is 400 Gcal/h. Two of the plant PTVM-100 boilers, B-1 and B-2 were commissioned in 1969 and refurbished in 1998. The other two PTVM-100 boilers B-3 and B-4 were commissioned in 1979 and 1981. Boiler B-3 is currently not operational. DKVR-6,5/13 Steam boilers B5 and B-6 were commissioned in 1983. Boiler B-6 was overhauled in 2008. Key technical data of the installed boilers is presented in Exhibit 59. [2]

Exhibit 59: CT-Vest Boilers Key Technical Data

Boiler Model	Qty	Heat Capacity	Pressure	Temperature °C		No. of Burners	Exhaust Gas Temp. °C	
		Gcal/hr	Kg/cm²	Inlet	Outlet	Pcs/Type	Gas	Oil
PTVM-100	4	100	16	70	150	16/ GDS-100	205	220
DKVR-6,5/13 Steam boilers	2	6,5 t/hr	13		194	2/ GMG-4		

Boilers B-1, B-2, B-4, B-5 and B-6 have been operated for approximately two-three months each on average during the 2016, 2017, and 2018 heating seasons [2]. The total lifetime hours in operation for the CT-Vest boilers have not been reported. An estimate of the accumulated total hours in operation for the CT-Vest boilers is presented

Exhibit 60: CT-Vest Estimated Total Accumulated Hours in Operation

	B-1	B-2	B-4	B-5	B-6
Model	PTVM-100	PTVM-100	PTVM-100	DKVR-6.5/13	DKVR-6.5/13
Commissioned	1968	1968	1981	1983	1983
Major Overhaul	1997	1998	1999	Not Done	2008
Average Annual operating Hours	1,464	2,226	1,912	1,859	503
Accumulated Hours in operation, end of 2018	30,744	44,520	36,322	65,053	5,033

Notes:

1. Average annual operating hours are estimated based on reported units' operation in 2016, 2017, and 2018.
2. Accumulated hours in operation are estimated based on years in operation since the last major overhaul and average annual operating hours.
3. For B-5, accumulated hours in operation are estimated based on years in operation since commissioning and average annual operating hours.

The water treatment plant has capacity of 120 m^3/h. During the heating season, CT Vest is providing heat supply to its designated service area of the Chisinau DH system.

The HFO handling includes: Rail station tank (50 m^3); storage tank - 4 pcs with a total volume of 10,000 m^3.

CT-Vest is equipped with the DH network circulation pumps presented in Exhibit 61:

Exhibit 61: CT-Vest Network Circulation Pumps

Model	Q-Ty	Data
14СД (SD)10 x 2	3	1250 m3/h, DP= 11,5 bar, 630 kW
СЭ (SE)-1250 - 140	3	1250 m3/h, DP=14,0 bar, 630 kW

CT-SUD BOILER PLANT

CT-Sud is located in the Centru (Central) district of the City of Chisinau. The plant area is 2.4 ha. The heat capacity is 310 Gcal/h and the installed steam production capacity is 30 t/h.

The plant TGVM-30 boilers B-1 and B-2 were commissioned in 1969. Boiler B-1 is currently not in operation. Boiler B-2 was overhauled in 2008. PTVM-50 boiler B-3 was commissioned in 1974 and overhauled in 2018.

Key technical data of the boilers is presented in Exhibit 62

Exhibit 62: CT-Sud Hot Water Boilers Main Technical Data

Boiler Model	Qty	Heat Capacity	Pressure
	Units	Gcal/hr	k/cm^2
TVGM 30	2	30	16
PTVM-50	1	50	16
KVGM-100	2	100	16
Steam boilers DKVR-10/13	3	10 t/h/ 7 Gcal/h	13

Out of eight installed boilers, four units are currently in operation (Exhibit 63).

Exhibit 63: CT-Sud Boilers Operating summary

Plant No.	Model	Commissioned	Overhauled	In Operation	Total Lifetime Hours
B-1	TVGM 30	1967	No	No	No info
B-2	TVGM 30	1967	2012	Yes	25,875
B-3	PTVM-50	1974	2018	Yes	39,450
B-4	KVGM-100	1985	2002	Yes	9,636
B-5	KVGM-100	1986	No	No	568
B-6	DKVR-10/13	1966	No	No	1,063
B-7	DE-6.5/14	2004	No	Yes	52,766
B-8	DKVR-10/13	1966	No	No	1,267

During the 2017 and 2018 heating season, boilers B-2, B-3 and B-7 were operating as base loaded for approximately 5 months each during the season. Boiler B-4 last time was in operation for approximately month and a half during the 2016 heating season.

HFO is supplied to CT- Sud site by a rail road. It is stored in 3 underground tanks (4,000 m^3 each). CT Sud is equipped with the DH network circulation pumps presented in Exhibit 64.

Exhibit 64: CT-Sud Network Circulation Pumps

Model	Q-Ty	Data
SE-800-100	2	800 m^3/h, Dp=10.0 bar, 320 kW
KRHA 700/200	4	1250 m^3/h, Dp=14.0 bar, 710 kW

SUBURBAN HEAT ONLY GENERATORS

Total actual DH load demand for the suburban heat generators is approximately 40 Gcal/h. Key technical information of the suburban heat only generators in Chisinau is presented in Exhibit 65.

Exhibit 65: Suburban Heat Only Generators

No.	Location and Heat Source Number	Model and Quantities of the HOB	Heat Capacity Gcal/h	Actual Demand Gcal/h
1	Vadul lui Voda, 6011	CV-G - 2,5 x 2	4.14	5.04
2	Bubuieci, 6021	CVa - 1,16 x 2	2.00	2.12
3	Bubuieci Primeriya, 6022	EN-50 x 2	0.20	0.20
4	Tohatin, 6031	CVa -0,63- Gn x 1 CVa -0,4- Gn x 1	0.89	0.98
5	Gidigich, 6041	DCVR 2,5/13x2	3.33	1.66
6	Durlesti, 6051	CV-G - 1,1 x 2 CV-G - 0,63 x 1	2.43	3.35
7	Vatra, 6061	EN-1000 x 2	2.00	1.89
8	STngera, 6071	Minsk-1 x 2	0.48	0.39
9	Bechoi Noi, 6003	Minsk-1 x 6	2.70	1.09
10	Dobruzha, 6081	ZiOSAB-2,5x 2	4.30	4.17
11	Gratiesti, 6091	DCVR 6,5/13x2	8.66	1.34
12	Kolonitsa school, 6121	CVa -0,4 - Gn x 1 CVa -0,16 - Gn x 1	0.48	0.46
13	Kolonitsa kinder garten, 6122	CVa -0,25 - Gn x 1 CVa -0,16 - Gn x 1	0.35	0.04
14	Kolonitsa Primeriya, 6123	EN-50 x 2	0.10	0.04
15	Kolonitsa ambulance, 6124	EN-50 x 2	0.10	0.09
16	Ciorescu, 6131	DCVR 10/13x2	13.32	3.99
17	Krikova, 6141	DCVR 6,5/13x1 CV-G - 2,5 x 2	8.63	4.35
18	Krikova school, 6142	CVa -0,4 - Gn x 2	0.69	0.46
19	Steuchen, 6161	DCVR 2,5/13x2 DCVR 10/13x1 DE 10/13x2	23.30	6.55
		TOTAL	**78.10**	**38.21**

3.2.7 OPERATING REGIME OF CHP AND CT PLANTS

CHP CET-2 (Source 1) is the main heat source for the main section of the Chisinau DH network. CET-2 produces the base load during the heating season. The minimum boiler output of one of the CET-2 unit is 200 t/h of steam, which results in district heat production capacity of approximately 70 – 80 Gcal/h, while typical summer load is around 30 – 40 Gcal/h. Therefore, during the off-heating season CHP CET-2 can only operate in a condensing mode (i.e. part of the heat produced is rejected to the ambient by cooling towers), which negatively impacts its economic performance. For this reason, CHP CET-1 (Source 2) has been kept operational and is being operated during the off-heating season to provide domestic hot water service for the Chisinau DH system.

During the heating season the DH service areas of CT Vest and CT Sud are isolated from the rest of the Chisinau DH system and CT Vest and CT Sud produce all the heat to their respective service areas. During the off-heating season the shut-off valves are opened, CT Vest and CT Sud are shut down and domestic hot water service for the whole Chisinau DH system is provided by CHP CET-1.

In the autumn, during the beginning of the heating season a small portion of heat can be delivered to CT Vest service area from the CHP CET- 1/CHP CET- 2 area and CT Vest can be operated in parallel. CT-East is not providing heat to the DH network.

Summary of the performance data for the whole DH system of Chisinau is presented in Exhibit 66 [9].

Exhibit 66: SA Termoelectrica Performance for 2016 – 2018

Plant	**HEAT GENERATION 2016- MAIN TECHNICAL DATA**					
	Heat	**Power**			**Fuel**	**Fuel**
	Gross	Generation	In house	Sold		
	Gcal	kWh	kWh	kWh	Nm^3	Gcal
CET-1	132,463	43,922,621	(7,535,654)	36,386,967	24,531,480	201,158
CET-2	1,135,800	708,334,617	(100,868,514)	607,466,103	275,580,527	2,259,760
CT-SUD	154,528		(5,272,963)		20,791,587	170,491
CT-VEST	230,918		(7,039,256)		30,390,683	249,204
TOTAL	1,653,709	752,257,238	(120,716,387)	643,853,070	351,294,277	2,880,613

Plant	HEAT GENERATION 2017 MAIN TECHNICAL DATA					
	Heat	**Power**			**Fuel**	**Fuel**
	Gross	Generation	In house	Sold		
	Gcal	kWh	kWh	kWh	Nm^3	Gcal
CET-1	146,791	32,400,895	(8,707,194)	23,693,701	23,828,962	195,397
CET-2	1,109,374	692,749,891	(97,196,656)	595,553,235	266,765,314	2,187,476
CT-SUD	143,821		(4,778,907)		19,437,568	159,388
CT-VEST	194,988		(5,922,184)		25,714,393	210,858
TOTAL	1,594,974	725,150,786	(116,604,941)	619,246,936	335,746,237	2,753,119

Plant	HEAT GENERATION 2018 MAIN TECHNICAL DATA					
	Heat	**Power**			**Fuel**	**Fuel**
	Gross	Generation	In house	Sold		
	Gcal	kWh	kWh	kWh	Nm^3	Gcal
CET-1	160,619	35,682,594	(9,005,402)	26,677,192	26,138,586	214,336
CET-2	1,155,818	725,166,752	(100,038,402)	625,128,350	279,947,719	2,295,571
CT-SUD	150,187		(4,741,430)		20,272,917	166,238
CT-VEST	198,333		(5,684,652)		26,284,131	215,530
TOTAL	1,664,956	760,849,346	(119,469,886)	651,805,542	352,643,353	2,891,675

3.2.8 DH NETWORK

DH NETWORK PIPING SYSTEMS

Length of the piping systems associated with the service areas of the major heating plants in Chisinau (based on revenue metering) are presented in Exhibit 67.

Exhibit 67: Length of the Chisinau DH Transmission Network Piping Systems

	Main Transmission Piping, m		Distribution Piping, m	Domestic Hot Water, m
Plant	Above Ground	Under Ground	Under Ground	Under Ground
CET-1	36,766	156,086	181,690	154,394
CET-2	20,240	116,290	137,052	106,642
CT-SUD	14,408	49,576	85,754	66,588

	Main Transmission Piping, m		Distribution Piping, m	Domestic Hot Water, m
CT-VEST	8,318	91,044	96,296	76,634
CT-EST	18,918	34,956	28,456	23,394
Total	**98,650**	**447,952**	**529,248**	**427,652**

Source: SA Termoelectrica

AGE OF DH NETWORK PIPING

The Chisinau District Heating Network is in need of rehabilitation, because of deterioration of the piping system hardware. The age of the DH pipes larger than 300mm DN is presented in Exhibit 68.

Exhibit 68: Age of large diameter DH pipes

In operation	Occurrence (%)	Cumulative (%)
<10 years	16%	16%
10 – 20 years	14%	30%
20 – 30 years	19%	49%
30 – 40 years	25%	74%
>40 years	26%	100%

A typical lifetime for installed DH pipes is approximately 30 years. About 50% of the Chisinau DH pipes have reached the end of their technical lifetime. The World Bank sponsored short-term, mid-term and long-term investment strategy is to renovate systematically all pipes over 40 years, which is approximately 230 km of piping. Replacement of pipes older than 40 years is projected to reduce heat losses in District Heating network from 19,7% to 18,2%. Upon completion of district heating network rehabilitation program (all large pipelines more than 20 years old today), the heat losses are projected to decrease to 15,6%. (Source: Termoelectrica).

PUMP STATIONS

Due to the mountain terrain of the city of Chisinau, the city heating network is designed divided into independent hydraulic zones. This necessitates operation of 17 pumping stations to provide required water circulation for the DH system. Most pump stations have been renovated, including replacement of pumps and other equipment. VFDs were installed in most pumping stations starting with 2006.

Three largest pumping stations were completely reconstructed in 2016 and a new pumping station was constructed in 2015; two other large pumping stations were renovated in 2018 and 2019 – all including VFDs.

The pumping stations are judged to be in satisfactory/good condition and are not expected to require significant replacement of main equipment during the next 10-year period.

A list of pumps installed at the DH pump stations, including pumps located at the heat the generation facilities is provided in Exhibit 69.

Exhibit 69: DH Network Pump Stations

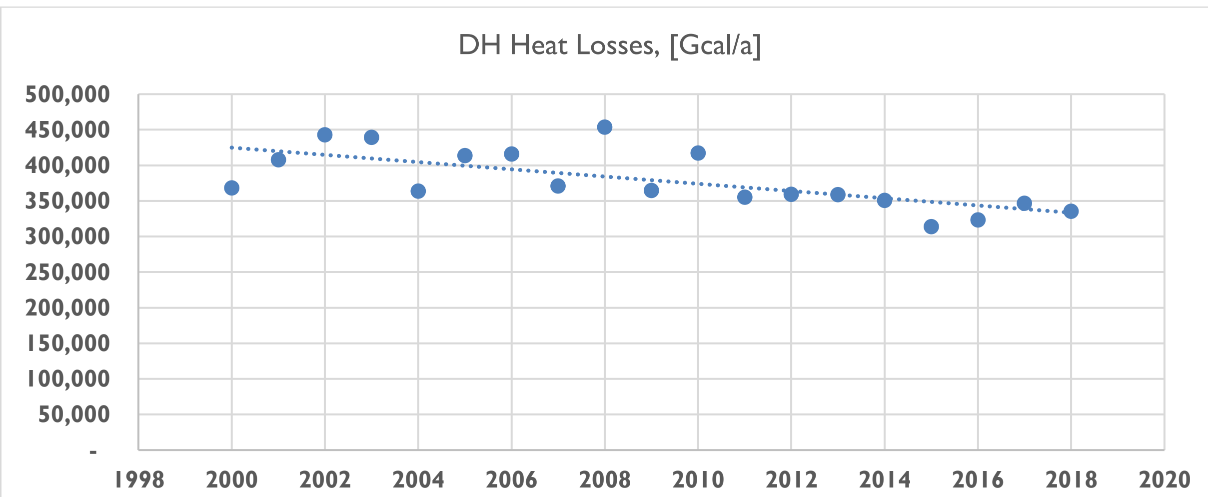
Pump group	Tag Number	Type	Qty	Unit Capacity, m3/h	Unit Electric drive unit, kW	Total Capacity, m3/h
2	SP-2	ME-200-500	3	500	75	1,500
3	SP-3	C3-800-55	3	500	48	1,500
4	SP-4	C3-800-100	6	800	100	4,800
5	SP-5	C3-800-100	4	800	100	3,200
6	SP-6	C3-800-55	3	800	55	2,400
7	SP-7	250LNN-600	3	800	110	2,400
8	SP-8	fl-3200-75	4	3,200	75	12,800
9	SP-9	250LNN-600	3	800	110	2,400
10	SP10	250LNN-600	3	800	110	2,400
12	SP12	C3-2500-60	3	2,500	60	7,500
13	SP13	C3-2500-60	4	2,500	60	10,000
14	SP14	200LNN-600	3	800	107	2,400
14	SP14	C3-800-100	1	800	100	800
15	SP15	10Cfl-6	3	500	70	1,500
16	SP16	6HK9-1	3	120	65	360
18	SP18	ME-200-500	3	500	74.9	1,500
19	SP19	MEN-125-100-250L	3	320	74.9	960
21	SP21	6HK9-1	1	120	65	120
21	SP21	K90/85	1	90	85	90
22	SP22	HKy-250-32	4	250	32	1,000
31	CET-2	C3 (SE)-5000x50	4	5,000 x 5 bar	1000	20,000
31	CET-2	C3 (SE)-1250x140	6	1,250x14bar	600	7,500
31	CET-2	C3 (SE)-5000x160	3	5,000 x 16 bar	1100	15,000
31	CET-2	C3 (SE)-2500x180	3	2,500 x 18 bar	1500	7,500
32	CT-VEST-1	14Cfl (SD)10x2	3	1,250 x 12 bar	630	3,750
32	CT-VEST-2	C3 (SE)-1250-140	3	1,250 x 14 bar	630	3,750

Pump group	Tag Number	Type	Qty	Unit Capacity, m3/h	Unit Electric drive unit, kW	Total Capacity, m3/h
33	CT-SUD-1	C3-800-100	2	800 x 11 bar	320	1,600
33	CT-SUD-2	krha 700/200	4	1,250 x 14 bar	710	5,000
34	CT-EST	C3-2500x180	3	2,500 x 18 bar	1600	7,500
35	CET-1	C3 (SE)-1250-140	7	1,250 x 14 bar	630	8,750

DH NETWORK HEAT AND WATER LOSSES

DH system heat losses for the last 18 years are presented in Exhibit 70 [10]. A notable reduction in heat losses of about 20% for the last 8 years is a result of the robust DH rehabilitation program which is ongoing since 2010.

Exhibit 70: DH network heat losses 2000 - 2018



Rehabilitation projects completed in recent years are presented in Exhibit 71 [11].

Exhibit 71: DH Network rehabilitation efforts

	DH Pipes Replaced, km	DH Insulation replaced, km	Share of Total Length	Change in Heat Losses, Y/Y%
2010	11.20	42.00	0.046	
2011	10.60	34.50	0.038	-15%
2012	9.40	32.00	0.035	1%
2013	11.40	29.90	0.035	0%

	DH Pipes Replaced, km	DH Insulation replaced, km	Share of Total Length	Change in Heat Losses, Y/Y%
2014	15.00	41.70	0.048	-2%
2015	2.90	17.00	0.017	-10%
2016	7.20	9.00	0.022	3%

The rehabilitation projects are financed by SA Termoelectrica and by the special World Bank project SACET. To date, approximately 24% of the total DH network had been rehabilitated. As a result, in 2018 the annual heat losses were reduced to 330,000 Gcal, or approximately 20% of the generated heat.

It has been reported that the DH network rehabilitation work will continue for the next 5-7 years, however, at a slower pace with the reduced scope of the projects. This is expected to result in additional reduction of annual heat losses during the period of 2025 – 2032 to about 15% of total generated heat, or approximately 260,000 Gcal/yr. However, Chisinau network losses are still above the prevailing heat losses level of about 10% in modern DH systems of a similar size.

While on an annual basis, system heat losses are about 20%, during the off-heating season, when the heat demand for DHW is low, the heat losses may reach 50% the of the total heat invoiced.

DH NETWORK RELIABILITY

The goal of the O&M and rehabilitation projects is to reduce system breakdowns, and heat and mass losses. The frequency of breakdowns is an indicator the network condition. Because of an inadequate rate of the network replacement, the reliability of the Chisinau DH network, and the system's efficiency have been decreasing, which negatively impacts the service quality.

The reliability of the district heating supply in Chisinau has a historical trend of deterioration as illustrated in Exhibit 72. In 2001 the average specific number of breakdowns per km for the entire network was reported at 0.8 breakdowns per km. In 2008, the same indicator reached 1.8 breakdowns per km, which is about almost 4 times higher compared to the modern DH systems in the EU (about 0.5 breakdowns per km).

The growing number of breakdowns in absolute and specific (per km) terms results in a decreased quality of service, and a significant level of heat losses. The latter reached 24% in 2008. Although heat losses have been reduced from 29% in 2005 to 24% in 2008, they are still notably above the level of about 10% prevailing in modern DH systems of a similar size.

Exhibit 72: Number of Absolute and Specific Breakdowns

	Transmission Network		**Distribution Network**		**Domestic Hot Water Network**		**Total, km**	
km	250		272		203		725	
	Breakdowns		Breakdowns		Breakdowns		Breakdowns	
	Total	per km	Total	per km	Total	per km	Total	per km
1998	185	0.74	N.R.	N.R.	348	0.58	533	0.74
2001	40	0.16	36	0.13	482	2.37	558	0.77
2008	302	1.19	78	0.29	927	4.56	1307	1.80

Notes:

1. N.R. - Not reported
2. Data for the recent years has not been provided by SA Termoelectrica

A substantially higher number of the absolute and specific numbers of breakdowns of the Domestic Hot Water (DHW) distribution network is largely explained by the fact that there was no hot water service during the period of 2001-2004 in Chisinau. During that period, the DHW distribution pipes have substantially corroded as they were not filled with the de-aerated water.

For the future pipeline replacement projects, it is recommended to utilize pre-insulated piping systems made of crosslinked polyethylene (PEX)-pipes (or equivalent), which eliminate pipeline failures due to corrosion.

DH SYSTEM MODES OF OPERATION

During the heating season, due to hydraulic constraints of the DH system, it is not possible to transfer any significant amounts of heat from CHPs CET-2 and CET-1 to the West and South service areas of the DH network. As a result, during the heating season, Chisinau DH network is separated into three service areas/loops supplying space heating and domestic hot water:

- Main service area/loop where heat is generated by CET-1 and CET-2
- West service area/loop, where heat is supplied by CT-Vest
- South service area/loop, where heat is supplied CT-Sud

Although certain amount of heat is transferred from CHP CET-2 to West service area at the beginning and end of the heating season.

During the off-heating season, the system operates in a single loop providing domestic hot water service, with main source of heat being CET-1.

DH NETWORK WATER PARAMETERS

The table in Exhibit 73 presents the winter mode of operation of the DH system during the extreme ambient conditions during the 2016- 2018 heating seasons.

Exhibit 73: Winter mode of operation

Heat Source	Service Area	T2	dT	Heat Recorded	Heat Calculated	Flow rate
		°C	°C	Gcal/h	Gcal/h	t/h
CET-1	Raza2	52.3	29.5	73.7	110.8	3,755
CET-2	Botanica	50.4	30.9	217.6	234.2	7,579
	Ciocana	51.1	30.9	112.8	124.0	4,012
	Linia de legatura	58.7	29.6	127.6	145.2	4,907
CT-SUD	Raza 1	54.4	25.9	24.0	24.0	927
	Raza 2	55.0	28.5	26.2	42.8	1,502
CT-VEST	Oras	53.7	25.8	62.9	83.4	3,233
	Alfa	54.3	26.4	25.7	31.8	1,206
	Average/Total	**53.7**	**28.4**	**670.3**	**796.2**	**27,121**

Notes:

1. Data in the table is for the coldest daily average ambient temperature of minus 15°C
2. T2 - return water temperatures
3. dT - difference between supply and return water temperatures

DH system is designed for 150°C supply water temperature and 70°C return water temperature. These values have been revised several times to 130°C/70°C, and 95°C/55°C. However, in practice the system is operated on average at supply temperature of approximately 75°C and difference between supply and return water temperatures (ΔT) of approximately 25°C. This operation results in significant circulating water flowrates, which create/exacerbate hydraulic bottlenecks in the system. While there is a potential for improving the system heat supply capacity through increasing its ΔT, operation at higher supply temperatures according to Termoelectrica could (and had) result in failure of DH piping systems due to their poor condition.

The minimum heat demand is observed during the off-heating season when only domestic hot water (DHW) service is provided to some of the customers. Average DHW load during 2018 was at 34 Gcal/h. The service was provided in a single loop at circulating water flow rate of approximately 2,500 m^3/h, supply water temperature of approximately 60°C and return water temperature of approximately 48°C. The DHW service is provided by CET-1 as the off-heating season heat load is below the minimum operating mode for the CET-2 turbine PT-80/130.

DH SERVICE AREAS

Average thermal loads and design circulating flow rates by the Chisinau DH service areas are presented in Exhibit 74.

Exhibit 74: DH Services Areas Data

Service Area	Average Space Heating. Gcal/h	Average DHW. Gcal/h	Design Water Flow, m^3/h
CT-SUD	91.8	6.5	2,340
CT-VEST	122.2	10.8	3,468
CET-1	307.3	24.1	7,100
CET-2	339.0	35.7	9,684

Notes:

1. CT-Sud includes two (2) pumping stations (SP#18, #19) with a capacity of 155 m^3/h and 692 m^3/h and a power load of 90 kW and 160 kW. The minimum required supply and return pressures at CT-Sud is approx. 9.3 and 2.0 atm.
2. The hydraulic regime of CT-Vest circuit is provided by 3 pumping stations (SP# 3, #9, #10) with capacity from 750 m^3/h up to 990 m^3/h and a power load from 200 kW up to 315 kW.
3. The DH piping cross connection between CET-1 and CET-2 is designed for transportation of 176.0 Gcal/h at water flowrate of 4,570 m^3/h.
4. The integrated process of joint operation of the CET-1/CET-2 circuit ensures maximum water flowrate of 14,260 m^3/h, including connecting line of 4,570 m^3/h,
5. "Botany" (SP #13) 5,050m^3/h, and "Ciocana" (SP#12), 4,640 m^3/h with minimum required supply and return pressures of 11.2 atm and 2.4 atm for CET-1 and 12.0 atm and 1.8 atm for CET-2.

3.2.9 CONDITION ASSESSMENT OF CHP PLANTS

In the power industry, typical practice is to periodically perform comprehensive condition assessments to determine equipment suitability for extended service and to establish duration of remaining service life of major equipment. Typical scope of such assessments involves destructive and nondestructive instrument aided inspections and laboratory analysis. Since the condition assessment reports for the CET-1 and CET-2 major equipment were not provided to the project, Worley employed methodology based on statistical analysis of the expected reliable service life demonstrated by equipment of similar design and materials of construction, subjected to similar operating conditions, metallurgy control and maintenance. The analysis is based on the reported data for the power plants of the CET-1 and CET-2 vintage that utilize the same standardized models of major equipment (such as boilers, steam turbines, generators, transformers, etc.), and the same overall plant design and configuration.

OPERATING HISTORY OF RUSSIAN TURBINES MODELS PT, P AND T

CET-1 and CET-2 were designed, constructed, and commissioned during the Soviet time. Like most of the power plants of this vintage CET-1 and CET-2 utilize standardized models of major equipment (such as boilers, steam turbines, generators, transformers, etc.), and their overall plant design and configuration is based on a centrally developed reference plant design. Over the years such power plants accumulated significant experience of long-term operation and maintenance of their equipment.

Types of turbines such as installed at CET-1 and CET-2 have been reported [12] to exceed 250,000 – 300,000 of lifetime operating hours when operated at steam throttle pressure of 13 MPa (Exhibit 75), and even 350,000 operating hours when operated at steam throttle pressure of 9 MPa (Exhibit 76).

Exhibit 75: Sample Operation Records of Soviet-type 13 MPa Steam Extraction Turbines

Turbine Model	OEM	Lifetime		Average Operation Cycle				
		Work hours	Start-ups	Duration	Operation	Repair	Stand-by	Start-ups
PT-60-130	LMZ	340,902	326	10,904	8,315	1,500	1,105	8
PT-65/75-130	LMZ	342,109	339	12,175	9,503	1,344	1,360	9
PT-65/75-131	LMZ	353,544	239	14,318	11,785	1,006	1,517	10
PT-80-130	LMZ	215,993	243	30,437	23,999	1,725	4,713	27
PT-80-130	LMZ	206,117	216	30,193	22,901	1,701	5,590	24
P-50-130	LMZ	234,493	193	19,126	12,932	1,441	4,753	9
P-50-130-15	LMZ	239,793	320	47,557	29,974	1,473	17,082	40
P-50-130-15	LMZ	244,123	304	41,152	27,165	1,960	12,035	34
P-100-130	TMZ	220,319	307	23,936	22,032	2,563	4,287	31
T-100-130	TMZ	275,711	443	27,046	21,109	1,359	3,473	34
T-100-130	TMZ	262,944	371	23,549	21,912	2,112	4,979	31
T-100-130	TMZ	316,478	246	20,761	16,657	1,495	2,610	13
T-100-130	TMZ	292,115	278	22,172	17,185	1,645	3,341	16
T-100/120-130	TMZ	274,907	219	22,303	13,327	1,806	2,670	15
AVERAGE OPERATION CYCLE					12,428	1,511	1,233	16

Exhibit 76: Sample Operation Records of Soviet-type 9 MPa Steam Extraction Turbines

Turbine Model	OEM	Lifetime		Average Operation Cycle				
		Work hours	Start-ups	Duration	Operation	Repair	Stand by	Start-ups
VPT-25	TMZ	380,793	302	19,947	17,309	1,465	1,194	15

Turbine Model	OEM	Lifetime		Average Operation Cycle				
		Work hours	Start-ups	Duration	Operation	Repair	Stand by	Start-ups
PT-25-90	TMZ	394,272	314	23,569	20,751	1,065	1,753	17
P-25-90	HTZ	341,224	269	16,183	13,124	1,113	1,947	10
P-25-90	HTZ	331,310	251	10,991	7,530	825	2,660	6
PT-25-90	TMZ	396,138	275	15,399	12,779	1,072	1,549	9
PT-25-90	TMZ	402,727	337	15,780	13,242	919	1,473	11
AVERAGE OPERATION CYCLE					14,123	1,077	1,763	11

This experience has been summarized and normalized in the Russian Federation standard RD-10-577-03 "Standard Regulatory Guidelines for Metallurgy Control and Service Life Extension of Major Components of Boilers, Steam Turbines and High-Pressure Pipelines of the Thermal Power Plants" [13]. This document is mandatory for the Russian thermal power plants. However, it is applicable and is being widely utilized by the power plants located in the former Soviet republics that operate the same models and vintage of equipment as the Russian power plants. Requirements related to metallurgy control for major components of boilers, steam turbines, and steam piping are specified in another Russian industry standard 17230282.27.100.005-2008 [14].

ASSESMENT OF REMAINING SERVICE LIFE FOR CET-1, CET-2 CHP UNITS

The RD-10-577-03 methodology is based on a good engineering practice approach of establishing remaining service life of high pressure / temperature components of the power plant equipment. The standard defines in general three stages of the power equipment life extension:

- Operation within the Fleet Service Life limits (FSLL)
- Operation within the Specific Service Life limits (SSLL) when the Fleet Service Life limit is exceeded
- Operation beyond Specific Service Life limits (BSLL).

The Fleet Service Life is expected reliable service life demonstrated by equipment of similar design and materials of construction, which was subjected to similar operating conditions, metallurgy control and maintenance.

The Specific Service Life is service life that has been determined for a particular unit with its unique metal properties, geometry and its actual operating conditions, normally after the FSLL hours have been exceeded.

Unit's FSLL, SSLL and BSLL operating periods typically characterized by different scopes of O&M efforts. When a decision is made to extend unit' operation into the SSLL period, and especially into the BSLL period, additional O&M efforts are typically planned for every 12000 - 20000 of the unit operating hours to supplement routine preventive maintenance. Scope of O&M efforts substantially increases especially during the BSLL period of operation to maintain unit's condition in compliance with the applicable technical standards. Additional work is expected to include major overhauls of boilers and steam turbines, such as replacement of boiler high pressure/temperature components (super heaters, reheaters, water walls and piping), overhaul of the entire steam turbine generator set, the turbine casing, rotor, seals, blades and bearings, and auxiliaries, Major overhaul work during the BSLL operation results in extended outages and additional costs as compared to the FSLL operation period.

The Fleet and Specific Service Life determinations are applicable to equipment components made of steel alloys that operate under high temperatures and pressure conditions, and are subject to slow plastic deformation under stress, a process known as creep.

The remaining useful service life of equipment components that are subjected to deterioration due to corrosion, erosion and other forms of wear and tear is determined by the results of periodic examinations of their de facto condition. Typically, such periodic examinations are conducted during the routine maintenance activities.

A comprehensive condition assessment is performed to determine equipment suitability for extended service and establish duration of the Specific Service Life once the equipment Fleet Service Life limit is reached. The scope of the assessment typically includes review of historical condition of equipment operation, non-destructive examinations (such as radiographic testing, magnetic particle Inspection, and liquid penetrant inspection), dimensional examinations (such as piping and tubing wall thickness), and metallurgy assessment to establish a remaining useful service life of a part

The following is a typical scope of a comprehensive condition assessment to establish remaining life and project possibility and conditions for extending an operation for a high pressure/temperature component beyond its FSLL resource:

- Analysis of the technical documentation, and operating history
- Non-destructive examinations;
- Inspection of supporting structural system;
- Metallurgical assessments in place and in the laboratory (sample cutouts) of the structure, properties and micro-damage of the metal;
- Determination of the remaining material strength and evaluation of the residual resource, considering actual operating conditions, and available research data;
- Developing recommendations for the duration of extended operating life, O&M and operating requirements, and schedule for the next comprehensive condition assessment effort

Comprehensive condition assessment determines scope and schedule for repairs and replacements that must be performed in order to continue unit operation.

Based on many years of comprehensive assessments of equipment accumulated 300,000 or more hours of operation, including analysis of equipment deterioration mechanisms, and metallurgy assessments, it has been predicted that the duration of the equipment Specific Service Life can be on average at least 1.35-1.5 times of its Fleet Service Life [15].

Fleet Service life and Specific Service life of a power unit is typically governed by condition of the unit’s steam turbine, as replacement or overhaul of the steam turbine major components typically represents the highest one-time lump sum cost.

Fleet Service Life for steam turbines is determined by their nominal output and throttle steam pressure and presented in Exhibit 77.

Exhibit 77: Fleet Service Life for Soviet-made turbines

OEM	Throttle Steam Pressure, MPa	Name Plate Output, MW	Fleet Service Life, 1,000 hours	Number of Start-Ups
Group A: UTZ (TMZ) Ural, Russia	Up to 9 13-24	≤ 50 50-250	270 220	900 600
Group B: LMZ St Petersburg, Russia	Up to 9 13-24	≤ 100 50-300	270 220	900 600
Group C: Turboatom Kharkov, Ukraine	Up to 9 13	≤ 50 160	270 200	900 600

Per the classification in Exhibit 77, the CET-2 turbines with output of 80 MW and throttle steam conditions of 13 MPa at 530°C belong to Group B-equipment, which have estimated Fleet Service Life of 220 thousand hours. The accumulated lifetime hours in operation for the CET-2 power units [2] are presented in Exhibit 78.

Exhibit 78: Lifetime operating hours of CET-2 Units

CET-2	UNIT 1	UNIT 2	UNIT 3
Commissioned	1976	1978	1980
Operating Hours, 2018	223,204	209,278	202,851

Technical Inspection (Technadzor) of Ministry of Economics of Moldova is a controlling agency, which oversees licensing of high-pressure piping and high-pressure boiler components in Moldova. Per the Technical Inspection requirements, boiler drums must undergo life / license extension assessment after 300 000 hours of operation. OEM recommendations are utilized for the steam turbines.

CET-2 Unit 1 that reached 220 thousand hours of operation is scheduled for a major overhaul during the summer of 2019 to renew its operating license. CET-2 Unit-2 is scheduled for a major overhaul in 2021, and CET-2 Unit-3 in 2024. The scopes of renovations for Unit 1 and 2 are reported to include major overhaul and modifications to the steam turbines and the boilers combustion systems. Unit 3 is scheduled to be overhauls without changes to its design [2]. The scope and the technical parameters of the CET-2 Units 1, and 2 renovation projects, and the Unit 3 overhaul project have been documented in the following SA Termoelectrica documents:

- Feasibility Assessment for Unit No.1 Turbine and Boiler Reconstruction / Retrofit project, CHP Source 1.

- Justification of the Reconstruction / Retrofit of the Medium-low Pressure Sections of the Source 1 turbines ПТ-80/100-130/13 to Assure their Operational Safety.

The CET-1 turbines belong to Group-C equipment with their power output less than 50 MW and throttle steam pressure of 9 MPa or less, at throttle steam temperature of 510 °C or less.

The current lifetime operating hours for the operating CET-1 boilers have reached their Fleet Service life limit. While the CET-1 operating steam turbines have not reached their Fleet Service life limit, the power equipment of this type has been mostly decommissioned, especially at the larger power plants. However, such equipment can continue operation, albeit not economically feasible, provided proper maintenance and repairs are performed to extend their service life.

Fleet Service life for the boilers high pressure and temperature parts is expected as follows:

- Boiler Headers
    - CET-2: 250,000 h
    - CET-1: 300,000 h
- Boilers' Drums constructed of metal grade 22K or 16 GNM [16] both for CET-1 and CET-2 is 300,000 h
- Main steam pipelines
    - CET-2: 250,000 h
    - CET-1: 350,000 h

In summary, the following remaining useful service life can be conservatively assumed for the CHPs major equipment:

- CET-2 Units 2, and 3 turbines have not reached their Fleet Service life of 220,000 h. Unit 2 turbine has approximately 12 thousand hours left before it would reach its Fleet Service life, Unit 3 has approximately 19 thousand hours left before it would reach its Fleet Service life. Unit I has reached its Fleet Service life, but it is scheduled for a major overhaul and license extension in 2019.
- Specific Service life for CET-2 Units 1, 2, 3 turbines is expected to be extended to 300,000 h, or additional 80,000 h beyond Fleet Service life limit. However, additional maintenance costs related to metallurgy assessments, maintenance and repairs are expected during the Specific Service life period.
- CET-2 Units 1, 2, 3 boilers have approximately 80,000 h of operation left before reaching their Fleet Service life limit.
- CET-2 Units 1, 2, 3 high pressure and temperature steam pipelines have approximately 50,000 h of operation left before reaching their Fleet Service life limit.
- CET-1 operating boilers B1 through B-4 have approximately 50,000 h of operation left before reaching their Fleet Service life limit.
- CET-1 operating steam turbines TG-1 and TG-2 have approximately 150,000 h of operation left before reaching their Fleet Service life limit.

At the pace of recent years of operation, given their low capacity factor (year 2018, capacity factor ~ 0.5), the CET-2 Units 2 and 3 can likely be in operation for approximately at least another 10 years before exceeding their Fleet Service life and start requiring additional maintenance costs related to metallurgy assessments, maintenance and repairs expected during the Specific Service life period. Unit 1 should also be able to continue operation for approximately 10 years once its overhaul is completed and it is successfully re-licensed.

The same could be concluded about the CET-1 units that in recent years were in operation for approximately 4000-4500 hours per year and should be capable of operating for another 10 years up to the end of their respective Fleet Service Resource Life.

REMAINING SERVICE LIFE OF HWB

The operating heat only boilers B-2 and B-3 located at the CET-2 site have accumulated 23,729 and 20,366 lifetime operating hours respectively. These boilers are operated during the peak heat demand periods at less than 1500 hours per year on average and should have approximately at least 150,000 h of useful operating life left before reaching their Fleet Service life limit. Given their low capacity factor, boilers B-2 and B-3 can likely be in operation for at least another 25-35 years before exceeding their Fleet Service life and start requiring additional maintenance costs.

The lifetime operating hours for the operating CT-Vest heat only boilers B-1, B-2, B-4, B-5 and B-6 have been estimated to range from approximately 5,000 to approximately 65,000. These boilers are operated during the heating season on average at approximately 1600 hours per year and should have approximately at least 100,000 - 150,000 h of useful operating life left before reaching their Fleet Service life limit. The CT-Vest boilers B-1, B-2, B-4, B-5 and B-6 can likely be in operation for at least another 25-30 years before exceeding their Fleet Service life and start requiring additional maintenance costs.

The operating heat only boilers B-2, B-3, B-4 and B-7 located at the CT-Sud site accumulated lifetime operating hours ranging from approximately 10,000 to 50,000. These boilers are operated during the heating season on average at approximately 3500 hours per year and should have approximately at least 100,000 - 150,000 h of useful operating life left before reaching their Fleet Service life limit. The CT-Sud boilers B-2, B-3, B-4 and B-7 can likely be in operation for at least another 25-30 years before exceeding their Fleet Service life and start requiring additional maintenance costs.

3.3 MINIMUM INVESTMENT NECESSARY FOR CONTINUOUS OPERATION

3.3.1 NEW GENEATING CAPACITIES PROJECTS

All the options for the new heat and power generation projects in Moldova in Section 8 of this report are proposed to replace the existing CHP capacities in Moldova. Some of the proposed options are configured to utilize the existing heat only boilers at the CET-2, and CT-Vest and CT-Sud sites. It is estimated that it would take approximately eight to ten years to develop, design, built and commissioned the new heat and power generation plants in Moldova (Exhibit 79).

Exhibit 79: Approximate project Development Schedule

Project Milestone	Approximate Duration Range
Assumed Start of the Project Development Activities	2021
Project Financial Decision	36 to 45 months
Design, Construction, and Commissioning	36 to 48 months
Commercial Operation	2028 - 2030

Under the considered options, the existing CET-1 and CET-2 CHP units are expected to be shut down once the new heat and power generating units are commissioned. However, depending upon the ultimately selected option the existing heat only boilers on CET-2, CT- Vest and CT-Sud may have to continue operation alongside with the new heat and power generating capacities. The new CHP capacities are expected to operate as base loaded, and the heat only boilers as peaking units, which should reduce their annual operating hours as compared to their historical operation.

3.3.2 INVESTMENTS TO EXTEND CET-1 AND CET-2 CHP UNITS OPERATION

It is reasonable to assume that the remaining lifetime and respective rehabilitation projects of CET-2 Units 1, 2 and 3 that are already planned and under way, should ensure operation of the CET-2 plant for approximately next 10 years.

CET-1 boilers and steam turbines at their current annual operating hours have sufficient resource life left for about 10 years before reaching their respective Fleet Service Resource Life. However, given the age and the vintage of the CET-1 equipment, it is judged that additional O&M expenditures related to the major overhauls of some of the equipment are likely to occur.

Indicative costs in Exhibit 80 to continue operation of the CET-1 and CET-2 plants for the next 10 years are assessed based on Worley in-house data and presented in 2019 USD.

Exhibit 80: Investments to continue operation

Plant	Costs,1000 x USD
CET-1	10,000
CET-2	30,000
Heat only boilers	5,000

The costs include major overhauls of the CET-1 and CET-2 CHP units through 2030, and an allowance for the additional O&M projects for CET-2, CT-Vest and CT Sud heat only boilers that are expected to operate for 10-15 years after the new CHP units are commissioned.

4 TASK 2: HEAT AND ELECTRICITY DEMAND AND SUPPLY

This section presents historical and current Chisinau District Heating system heat load covered by the existing CHPs and local boilers supplying heat to the common DH network. It also presents analysis and results of the heat load forecast and the heat Load Duration Curve (LDC) that take into account the impact of the potential change of the customer base, energy efficiency improvement in the DH system.

For the electrical load assessment, this section provides historical and current electricity demand of Moldova by sectors, load characteristic, seasonal and hourly profiles, base and peak loads. A load forecast is developed, factoring the impact of consumer base changes, energy efficiency impact and the relevant conditions.

On the supply side, information on power imports, and power generation by all sources, their availability, planned and unplanned outages based on historical data also considering the near-term plans to implement new power supply sources, including an asynchronous connection with the ENTSO-E system is gathered and evaluated. This provides information on current and anticipated demand and supply situation in the energy sector and identifies the gaps between the supply and demand.

4.1 CHISINAU DH SYSTEM

SA Termoelectrica is the only company specializing in centralized supply of heat and domestic hot water to customers in Chisinau and its suburbs. SA Termoelectrica is the largest electric power generating company in Moldova (excluding the Transnistria region).

The main activities of the company include:

- Generation of electric power;
- Production, supply and distribution of thermal energy (also includes domestic hot water) to residential, commercial, public, government and industrial consumers.
- The company owns and operates all major electric power and heat generating facilities in Chisinau area.
- The company generates annually about 1,370 thousand Gcal of thermal energy for heating and domestic hot water, and delivers the thermal energy to more than 5,700 consumers, including 600 government entities, 800 commercial customers, 300 private houses, and over 208,000 residential apartments located in 3,931 residential buildings;
- SA Termolectrica generates and delivers to the national energy system about 15% of the total electric power energy consumed by the country (excluding the Transnistria region).
- The company also has a capability to supply process steam.

The SA Thermoelectric history, its heat and power generating assets and operation for the DH system are described in Section 3.1 of this report.

4.1.1 DH SYSTEM IMPROVEMENTS

Since 2009 with the strong support of the World Bank, the DH sector in Chisinau has embarked on a comprehensive institutional, corporate and financial restructuring reform. This effort resulted in reversing a downward spiral for DH services in Chisinau, such as lack of funds for maintenance and investments, poor service, loss of customers and financial losses. The recovery process includes:

- Completed corporate restructuring and optimization with creation of a single management operator SA Termoelectrica in 2015
- Major staff downsizing
- Reduction of thermal losses and auxiliary electric power consumption
- Improvement in service and customer relationships

In 2014, the District Heating Efficiency Improvement Project (DHEIP) commenced funded by the World Bank. The DNIEIP objective is to improve operational efficiency and financial viability of the new district heating company, and to improve quality and reliability of the heating services in Chisinau.

Effective 2015, the DHEIP supports investments in:

- Modernization of largest pumping stations to reduce electricity consumption by implementing more efficient variable flow operation mode of the DH system;
- Rehabilitation of selected segments of the DH distribution network to ensure uninterruptable DH service and reduction in losses of heat and hot water;
- Replacement of old and inefficient central heat substations (CHS) with modern fully-automated individual building level heat substations (IHS) for more efficient and secure heat supply to the end-users; and
- Reconnection to the DH of selected public institutions, which were earlier disconnected.

Efforts are under way to identify least-cost investments in heat and electric power production (supply side) to improve fuel efficiency and to increase electric power generation by the CHP plants. The ongoing DHEIP revealed a significant need for investments in the energy supply infrastructure, which is approaching the end of its operational life and could pose a threat to uninterrupted heat supply in Chisinau, as well as continued investment efforts on the demand side for more efficient and secure supply of heat and more demand management.

4.2 DISTRICT HEAT DEMAND

4.2.1 CHISINAU DH GENERATION

During the period of 2005-2010, the companies providing centralized heat supply services in Chisinau accumulated significant debts that caused their financial insolvency. Limited investments over the past 20 years have led to decay and obsolescence of the distribution system equipment and the thermal generating facilities, causing their inefficient unreliable operation, poor quality of services, high energy losses. This process resulted in high production, transportation and distribution costs of thermal energy for the final consumers. All these factors led to a trend of customers installing individual systems for heating and hot water supply and the disconnecting from the DH network.

Most of households in Chisinau used to be connected to the DH system. However, the lack of confidence in the DH system has encouraged multiple customers to disconnect from the system and turn to the alternative heat sources, such as apartment-level, gas-fired, heat-only boilers and electric heaters. Most of the newly built buildings in Chisinau are not supplied by the centralized DH system.

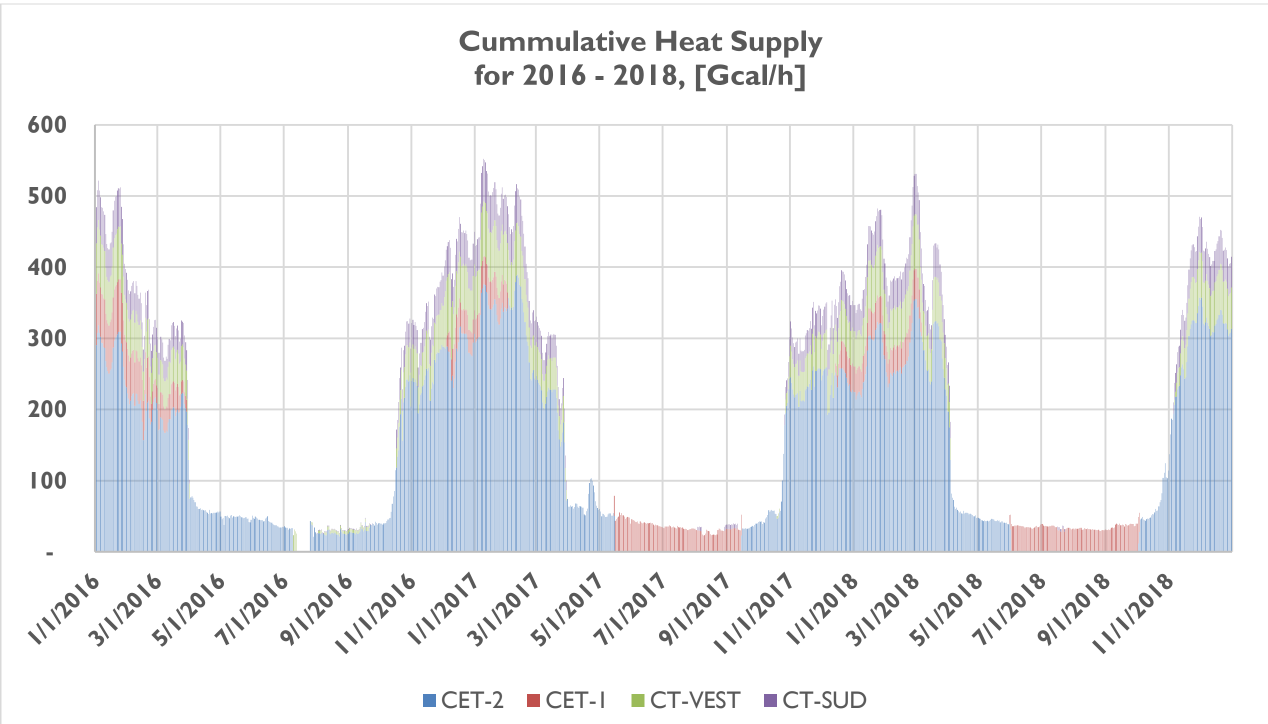
Since 2005, heat sales remained flat despite a strong economic growth. In 2007, 77% of the Chisinau households received their heat from the central heating network, while 23% of the households have invested in autonomous heat sources. However, most of the population cannot afford capital cost associated with switching to a different source of heat supply and continue receiving services from the DH heat system.

Recent years data demonstrate stabilization of the downward trend indicating that the measures taken, and the investments in the DH sector have been producing meaningful results.

CURRENT LOAD DEMAND

Seasonal heat load fluctuation during the 2016 - 2018 is shown in Exhibit 81 [17]

Exhibit 81: Gross heat load for 2016 to 2018



Average monthly heat generation and consumption during the 2016-2018 three-year period is presented in Exhibit 82 [18]

Exhibit 82: 2016-18 Average Monthly Heat Demand and Supply

	Average Monthly Heat Generation by Source, Gcal/month					Average Monthly Heat Demand by Service Type, Gcal/month	
	CET-2	CET-1	CT-VEST	CT-SUD	Total	DHW	SPH
JAN	221,670	35,848	48,834	36,090	342,443	23,142	319,301
FEB	179,937	20,511	38,508	28,443	267,399	19,801	247,598
MAR	167,563	9,151	34,514	25,141	236,369	21,070	215,299
APR	48,798	-	1,311	877	50,986	24,125	26,861
MAY	28,957	6,555	-	-	35,513	35,513	OHS
JUN	10,288	17,985	-	-	28,273	28,273	OHS
JUL	4,011	16,757	937	259	21,964	21,964	OHS
AUG	6,393	14,791	925	615	22,724	22,724	OHS
SEP	12,083	12,565	814	748	26,211	26,211	OHS
OCT	67,069	834	5,881	4,647	78,431	24,921	53,510
NOV	177,919	-	31,536	24,397	233,852	19,687	214,164
DEC	210,394	12,323	44,387	31,313	298,417	21,025	277,391
Total	1,135,083	147,320	207,646	152,531	1,642,581	288,456	1,354,124

Notes:

1. SPH – Space Heating and Ventilation
2. DHW – Domestic Hot Water
3. OHS - Off-heating season
4. Approximately 208,000 flats served by the district heating company with total area of 8,112,000 m^2
5. Average living area per flat is 39 m^2
6. Total demand for public customers is equivalent to demand of approximately 35,000 flats
7. Domestic hot water services provided to 108,000 customers
8. Total equivalent service area including public and residential customers is approximately 9.477,000 m^2
9. Specific heat demand is 166.15 $kWh/m^2/yr$

During the off-heating season, when the heat demand for DHW is low, the heat losses may reach approximately 50% the of the total heat demand as illustrated in Exhibit 83 that shows gross and net average monthly heat consumption by the domestic hot water service.

Exhibit 83: 2016-18 Average Monthly Heat Consumption by Domestic Hot Water Service

	Net Demand, Gcal/month	Losses, %	Gross Demand, Gcal/month
JAN	18,977	18%	23,142
FEB	17,141	13%	19,801
MAR	17,839	15%	21,070
APR	15,794	35%	24,125
MAY	16,885	52%	35,513
JUN	14,885	47%	28,273
JUL	10,673	51%	21,964
AUG	11,908	48%	22,724
SEP	14,236	46%	26,211
OCT	15,182	39%	24,921
NOV	16,528	16%	19,687
DEC	17,839	15%	21,025
Total	187,885	35%	288,456

4.2.2 OPERATING MODES OF DH SYSTEM

Due to the Chisinau mountainous terrain, the DH system requires operation of 17 pumping stations. Most pumping stations were renovated, including replacement of pumps and other equipment. VFDs were installed in most pumping stations starting with 2006.

Three largest pumping stations were completely reconstructed in 2016 and a new pumping station was constructed in 2015; two other large pumping stations were renovated in 2018 and 2019, all equipped with VFDs to improve system efficiency by enabling variable flow rate of the circulating water.

The pumping stations are considered to be in satisfactory/good condition and are not expected to require significant replacement of main equipment during the next 10-year period.

During the heating season, due to hydraulic constraints of the DH system, it is not possible to transfer any significant amounts of heat from CHPs CET-2 and CET-1 to the West and South service areas of the DH network. As a result, during the heating season, Chisinau DH network is separated into three service areas/loops supplying space heating and domestic hot water:

- Main service area/loop where heat is generated by CET-1 and CET-2
- West service area/loop, where heat is supplied by CT-Vest
- South service area/loop, where heat is supplied CT-Sud

Although certain amount of heat is transferred from CHP CET-2 to the West DH service at the beginning and end of the heating season, during most of the heating season it is not possible to transfer any significant amounts of heat from CHP CET-2 (or CET-1) to the West and South DH service areas without a major modification of the DH system. Such major modification to enable a single loop operation of the city DH system during the heating season is considered by Termoelectrica as not feasible.

During the off-heating season, the system operates in a single loop providing domestic hot water service, with main source of heat being CET-1.

At this time, no major modifications of the DH system are expected in the next decade that may change dramatically the today modes of operation, system hydraulic profile and temperature regimes.

4.3 DEMAND PROJECTION FOR DH SYSTEM

New heat and power generating capacities are expected to be commissioned in 2030. Heat demand projection for the Chisinau DH system for 2030 is a critical input for proper design and sizing of the new plants. The starting point for any projection exercise is to establish the current demand. The current demand is assumed based on the 2016-2018 three-year heat load and heat energy generation data presented in Exhibit 81, Exhibit 82, and Exhibit 83. The heat demand projection takes into account future potential change of customer base, and energy efficiency improvements of the DH system (discussed in Section 3.2.8) and improvements related to the demand side management. Ambient conditions in Chisinau are assumed to be unchanged for the next 30 years.

4.3.1 CHANGES IN CUSTOMER BASE

Currently, SA Termoelectrica supplies more than 208,000 residential customers with space heating service, and approximately 108,000 customers receive domestic hot water service. There is a potential for over 100,000 of existing space heating service customers to start receiving domestic hot water service in the future. New flats being built in Chisinau are also considered as potential future customers for the space heating and domestic hot water services. The recent years statistics of the new built residential dwellings are presented in Exhibit 84 [19].

Exhibit 84: New built residential dwellings in Chisinau, multi-story buildings

Year	# of apartments (1000)	Total Living Area, 1000 m^2	Average Living Area per Apartment, m^2
2005	250	8,643	35
2006	246	8,567	35
2007	249	8,732	35
2008	254	8,959	35
2009	258	9,111	35
2010	260	9,378	36
2011	264	9,601	36

Year	# of apartments (1000)	Total Living Area, 1000 m^2	Average Living Area per Apartment, m^2
2012	266	9,687	36
2013	271	9,867	36
2014	270	10,132	38
2015	274	10,306	38
2016	258	10,188	39
2017	267	10,370	39

An annual growth of approximately 1.4% per year has been reported for the new flat construction for the last five years. However, there is a certain amount of the older residential buildings that are demolished each year. Some of them are current district heating company customers.

Heat demand for the public sector customers (kindergartens, schools, medical facilities, commercial entities) is approximately 172,000 Gcal/yr for space heating and 16,200 Gcal/yr for domestic hot water service. There are total of 1,140 customers in this category with the total heated area of approximately 1,250,000m^2 which is equivalent to approximately 35,000 residential flats.

Customers that left DH services years ago (approximately 22,000 flats) are also considered as potential future customers. The pace the former customers rejoining the DH services will have an impact on future heat demand in 2030.

4.3.2 ENERGY EFFICIENCY IMPROVEMENTS

Future demand in 2030 will depend on the pace of implementation of the DH system improvements and demand side management (DSM) measures in the existing buildings. Demand Side Management measures could be applied to both the district heating company and the customers heating systems, and typically have a notable effect on the gross heat demand at the plants' terminals. Ongoing modernization of the DH substations that transfer heat to individual buildings helps to facilitate heat on demand controls that should produce savings in average heat consumption at the household level.

The significant reduction, so far, in heat consumption is a result of a combination of measures in the DH sector. These included prior measures to install Individual Thermal Points (ITP) equipped with heat meters, and heat regulators (thermostatic valves) in radiators, and metering of consumption.

Some DSM measures, important for the efficiency of the heat supply and related to buildings, insulation, etc. are difficult to implement on a bigger scale due to their high costs. Therefore, there is an expectation for a slower implementation of such measures in Chisinau district heating sector.

The list of DSM measures to be implemented goes beyond investments related to insulation of walls and roofs. The target remains to reduce the energy consumption per square meter from approximately 110-140 kWh/m^2/yr down to 60-75 kWh/m^2/year in multi-story residential buildings.

Sample information from the ESCO project [20] on the expected effect of implementation of DSM measures in residential and public buildings is presented in Exhibit 85 and Exhibit 86.

Exhibit 85: ESCO project DSM effect estimation in private sector for typical residential buildings

Building Element	Area, m^2	Initial Energy Losses, kWh/yr	DSM Effect	Energy Losses after DSM, kWh/yr
Roof	372	8,958	4%	8,600
Windows	281	35,116	14%	30,200
Walls	1239	216,298	50%	108,149
ITP	1	16,333	10%	14,700
TOTAL		276,706		161,649
Specific Energy Demand	$kWh/m^2/yr$	123		72
DSM Effect		100%	42%	58%

Exhibit 86: ESCO project DSM effect estimation in public sector

Building Element	Area, m^2	Initial Energy Losses, kWh/yr	DSM Effect	Energy Losses after DSM, kWh/yr
Roof	1,789	82,652	11%	73,560
Windows	589	127,376	16%	106,996
Walls	2,633	376,158	36%	240,741
ITP	1	36,635	8%	33,704
TOTAL		622,820		455,001
Specific Energy Demand	$kWh/m^2/yr$	174		127
DSM Effect		100%	27%	73%

According to the World Bank evaluations, there is potential for approximately 40% of additional heat demand reduction due to DSM measures in the buildings alone, which could be implemented in the next several years. However, achieving significant improvement in energy efficiency of the existing buildings is slow and capital-intensive process.

4.3.3 HEAT LOAD FORECAST AND LOAD DURATION CURVE

District heating demand can be characterized by the peak heat load and the annual heat production. The peak demand (Gcal/h) is important for the sizing of the district heating sources and the supply network system. Annual district heating production (Gcal/y) determines the heat revenues and the fuel consumption requirement.

HEAT PRODUCTION FORECAST

DH system heat production forecast is performed based on the three-year Chisinau DH operation data presented earlier in this report in Exhibit 81, Exhibit 82, and Exhibit 83. The assumed future changes in customer base, DSM measures and reductions in DH heat losses are presented in Exhibit 87.

Exhibit 87: DH Heat Demand Forecast Assumptions

Item	Units	Value
Flats receiving space heating service in 2018	units	208,000
Average living area per existing flat	m^2	39
Flats receiving DHW service in 2018	units	108,000
Total area receiving space heating in 2018, incl. residential and public	m^2	9,447,000
Newly built flats during 2018 - 2030 that are receiving space heating service	Flats/year	5500
Average living area per new built flat	m^2	80
Existing flats currently receiving space heating service and demolished during 2018-2030	Flats/year	450
Former space heating service customers re-connecting to DH	Flats /year	1500
Former DHW service customers re-connecting to DH	Flats/year	5000
Existing space heating service customers that implemented DSM measures during 2018 - 2030	Flats/year	1300
2016-18 Specific heat demand	$kWh/m^2/yr$	166
Improved Specific heat demand due to DSM measures	$kWh/m^2/yr$	116
Specific heat demand for new built flats	$kWh/m^2/yr$	83
2016-18 Average gross heat generated for space heating	Gcal/year	1,354,124
2016-18 Average gross heat generated for DHW	Gcal/year	288,456
DH system losses in 2018	%	19.7
DH system losses in 2030	%	15.6
Average people per flat		2.9

Results of the heat demand forecast analysis for 2030 are presented in Exhibit 88.

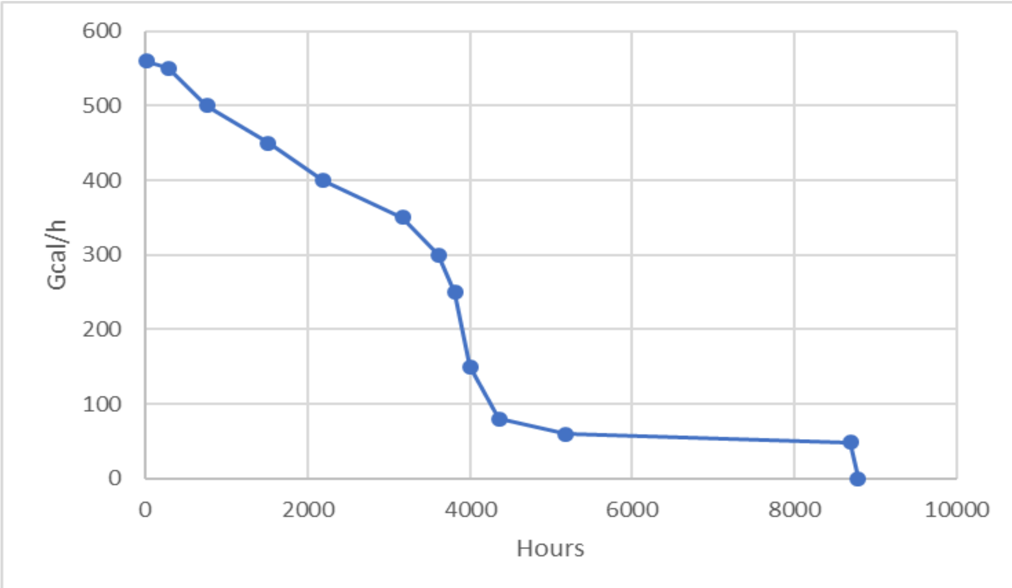
Exhibit 88: Heat Demand Forecast

Space Heating	**Area, m2**	**Demand, Gcal/y**
Average for 2016-18	9,477,000	1,354,000
Existing flats with improved efficiency due to DSM	608,000	-26,000
Returned customers	702,000	100,000
Demolished flats	-211,000	-30,000
New built flats	4,800,000	343,000
Subtotal for space heating	***15,376,000***	***1,741,000***
Domestic Hot water	**Person**	**Demand, Gcal/y**
Total people receiving DHW service in 2016-18	313,200	288,500
Returned DHW customers	174,000	160,300
Lost DHW customers due to flats demolished	-15,700	-14,400
New DHW customers in new built flats	174,000	160,300
Subtotal for DHW	***645,500***	***594,700***
Total DH Heat Demand in 2030 based on current DH heat losses		2,335,700
Reduction in Heat Losses in 2030		-95,800
Total Annual Heat Production Demand in 2030		**2,239,900**

PEAK HEAT LOAD AND LOAD DURATION CURVE

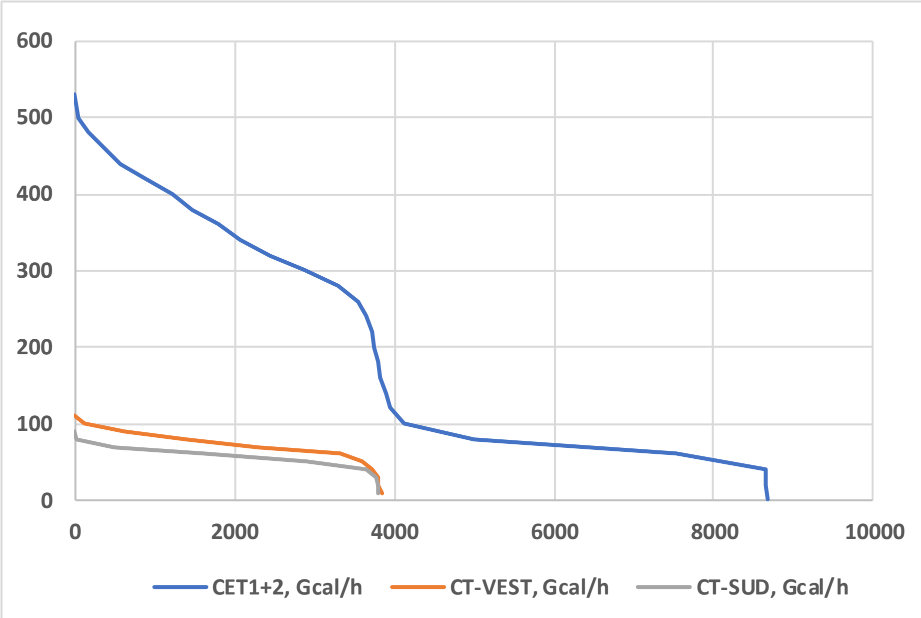
Heat demand as a function of a cold weather is typically normalized by a cumulative frequency ambient temperature duration curve. The total Chisinau DH peak demand during the 2016-18 seasons for Chisinau DH system was reported at 552 Gcal/h, including 406 Gcal/h for the CET-1 and CET-2 service area, 81 Gcal/h for the CT-Vest service area and 65 Gcal/h for the CT-Sud service areas (Exhibit 81). Exhibit 89 shows the data plotted for the city of Chisinau for the 2016-18 seasons, and load durations developed based on ambient temperatures obtained from a public source [21]. The peak demand is the highest point on the curve, while annual heat production is the area underneath the curve.

Exhibit 89: Chisinau District Heating – Load Duration Curve 2016-2018



While the total annual heat production in 2030 is forecasted to increase by a factor of 1.36 as compared to average annual 2016-18 heat production, the peak heat load is expected to increase in 2030 by a factor of approximately 1.23, or from 552 Gcal/ to 660 Gcal/h based on an assumed diversity factor of 0.9 [22]. That is, the maximum heat demand for a centrally supplied peak load is expected to be lower than the aggregate of the individual peak loads of all buildings as these individual peak loads are non-coincident. This is due to a diversity of all the multiple residential, public, commercial space heating and domestic hot water loads in the Chisinau DH system. For example, peak loads of the public buildings may not coincide in time with the peak loads of the residential buildings. The diversity factor does not affect the annual heat production, it only affects the load. Exhibit 90 presents the Load Duration Curves (LDC) forecast for the CET-1 and CET2, CT-Vest and CT-Sud service areas in 2030 that are used as a basis for the options analysis in this study.

Exhibit 90: Load Duration Curve, Year 2030, Gcal/h



4.4 ELECTRIC POWER DEMAND AND SUPPLY

4.4.1 HISTORICAL POWER GENERATION AND POWER IMPORTS

According to the International Energy Agency (IEA) [23], which presents the electricity consumption jointly for the Moldova's left and right bank of the Dniester River power systems, the electricity demand in Moldova dropped from about 9,000 GWh in 1990 to below 4,000 GWh in 2000. In 2007, electricity consumption of 4,155 GWh was reported by the IEA. This recent increase in demand is confirmed by input data published in Moldova. Since 2001, the electricity demand increased by about 3% each year to 4,159 GWh in 2017. The power energy demand increase is mainly fueled by increasing household and commercial consumption (8% and +13% respectively), while industrial and agricultural consumption declined (-5% and -15%).

Exhibit 91 presents the power generation and import / export information for the period from 2007 to 2018. [24].

Exhibit 91: 2007-2018 Historical Power generation, imports and exports, GWh/yr

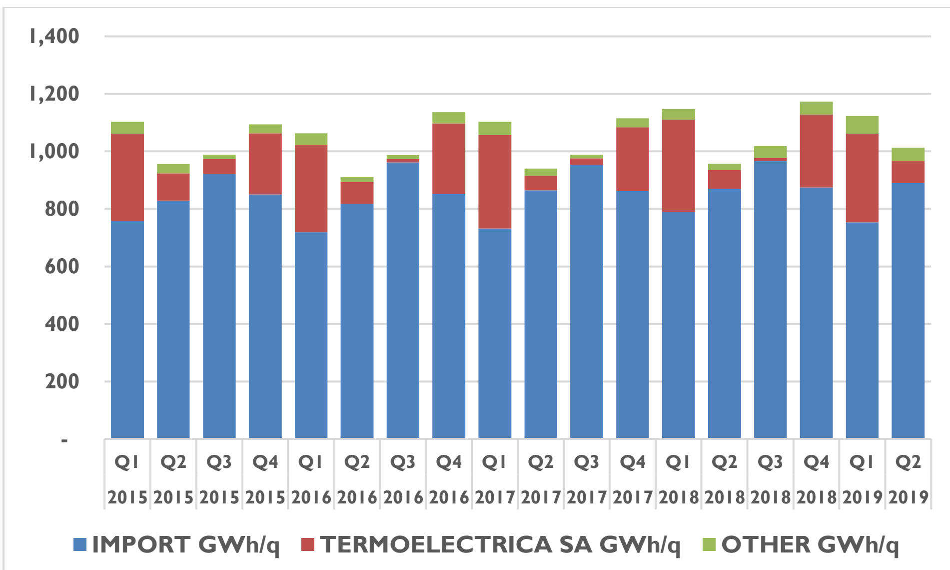
Power Source	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
MGRES	2311	2436	4529	4313	3954	4070	2788	3622	4316	4170	3315	3668
Dubassari	274	306	302	327	275	234	264	257	214	187	233	227
CET-1	122	114	109	77	55	43	46	52	36	33	23	26
CET-2	682	641	639	665	656	636	594	601	627	607	596	625
CET-Nord	55	55	54	57	58	55	49	50	53	55	48	54

Power Source	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
CHE Costesti	33	82	54	78	76	34	45	58	50	39	47	44
Sugar Mills	1	5	1	4	4	3	4	15	1	2	2	2
RES	0	0	0	0	0	0	0	0	14	14	19	47
Ukraine	2622	2958	7	25	666	836	1456	731	18	4	1134	956
Romania	-315	-775	-412	-370	-529	-595	0	0	0	0	0	0
Total	5786	5822	5283	5176	5215	5317	5245	5387	5329	5111	5417	5647

Note: RES – Renewable Energy Sources

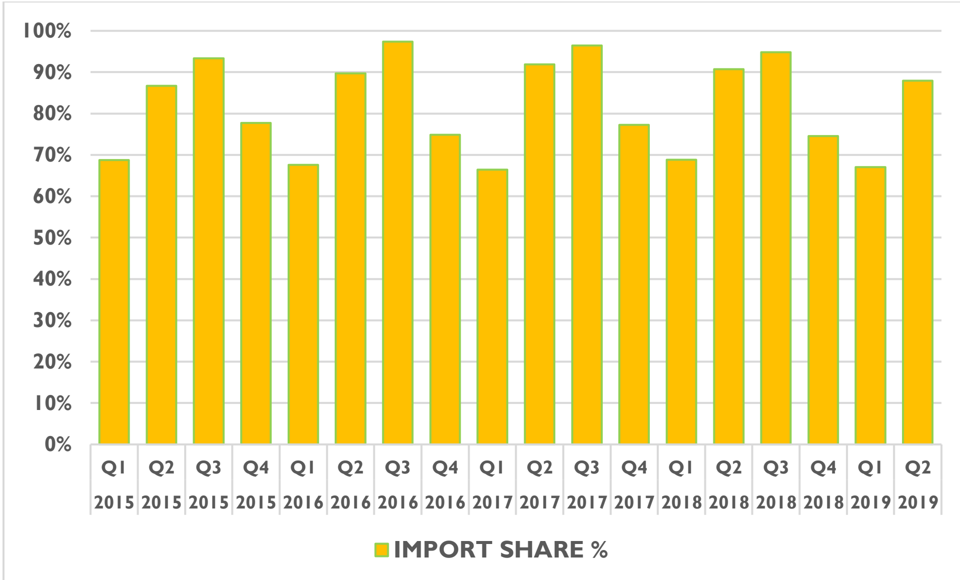
Exhibit 92 presents 2015-18 power generation and imports for the right bank system on a quarterly basis [25].

Exhibit 92: Right Bank System Power Generation and Imports in GWh/quarter



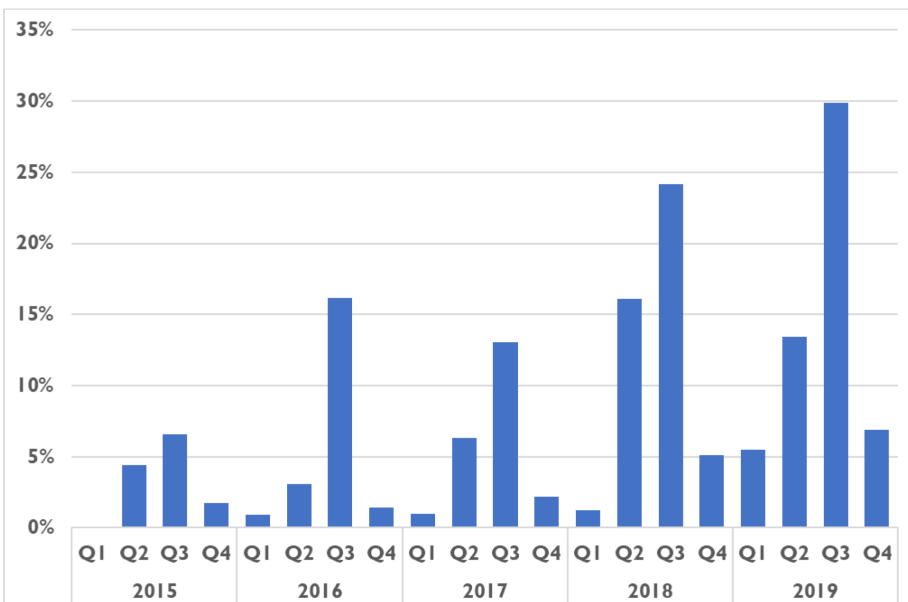
About 75% - 80% of the right bank available electric power comes either from Ukraine, or from the left bank located MGRES and Dubassari HPP (Exhibit 93).

Exhibit 93: Share of Right Bank Power Imports in the total Power Generation Mix, for 2015 – 2018, %



In recent years, power generation by the RES has notably increased, reaching during the summer months approximately 15-30% of the total power produced by the right bank system generators (Exhibit 94).

Exhibit 94: Share of RES in Right Bank electricity generation mix, 2015 – 2019



The annual power consumption by the Dniester right bank system has increased by approximately 6.1% between 2010 and 2017, at an average annual growth rate of approximately 0.76%.

4.4.2 POWER NETWORK IMPROVEMENT PROJECTS.

The following projects and plans are under way to improve the right bank power transmissions network.

MOLDELECTRICA POWER NETWORK ENHANCEMENT PROJECTS

The following considerations are included in the Moldelectrica Grid development plan to 2027 [26]:

- The target of diversification of electricity supply sources is envisaged to be achieved by accessing the EU electricity market, which could be accomplished by the Back-to-Back (B2B) asynchronous interconnections with ENTSO-E at Vulcănești, Bălți and Ungheni, capable of power flow and voltage control to minimize the power system loses.
- At the same time, there is a need for extension of interconnections with Romania in order to increase operational security and the interface transmission capacity.
- In addition, interconnection with EU can potentially provide better wholesale power prices because of increased competition that could lead to a lower electricity price for the end consumers.

MOLDELECTRICA TRANSMISSION NETWORK REHABILITATION PROJECT

- The "SE Moldelectrica Transmission Network Rehabilitation Project" that is financed by European Bank for Reconstruction and Development (20 mln. USD), European Investment Bank (17 mln. USD) and Neighborhood Investment Facility (8 mln. EUR grant) is underway. The project has an estimated implementation timeframe of 4 years and is intended for replacement of old equipment and reconstruction/construction of the 110 kV Overhead Transmission Lines (OHTL) and 110kV substations.

REHABILITATION OF THE EXISTING OVER HEAD TRANSMISSION LINES

The following existing OHTLs are to be rehabilitated to improve reliability of power supply of Moldova power consumers:

- 400 kV Vulcanesti - Isaccea.
- 330 kV
- 110 kV
- Rehabilitation of the existing and installation of new 35 kV OHTL's

INTERCHANGE CAPACITY ENHANCEMENT - BACK TO BACK CONVERSION STATIONS

According to the Energy Strategy of Republic of Moldova, the following Back-to-Back asynchronous interconnection options have been analyzed:

- 400 kV OHL Isaccea – Vulcănești – Chișinău;
- 400 kV OHL Bălți – Suceava;
- 400 kV OHL Strășeni – Ungheni (an auxiliary line for increasing transit flow through internal grid) and 400 kV OHL Ungheni – Iași.

Calculation of load flow regimes have been performed by considering interconnected synchronous operation with IPS/UPS [27] powers system (interconnection with the Power system of Ukraine) and asynchronous operation, via Back-to-Back stations, with ENTSO-E continental power system (interconnection with Power system of Romania). The planned interchange capacity enhancement projects are presented in Exhibit 95 [28].

Exhibit 95: Interchange Capacity Enhancement Projects planned schedules.

Project	From	To	Length km	Voltage kV	Commissioning Date
B2B station at Vulcanesti	Romania	Vulcanesti			2023
Vulcanesti-Chisinau	Vulcanesti	Chisinau	159	400	2023
Balti-Suceava	Balti (MD)	Suceava (RO)	158	400	2027

4.4.3 GAPS IN ELECTRIC POWER SUPPLY AND DEMAND

There are several issues identified and summarized herein, which are consistent with information from the other sources [29]:

- The largest generating capacity in Moldova is MGRES, which is located on the Dniester left bank, while the country major demand is on the right bank
- Lack of synchronous power interconnections with the ENTSO-E system, and thus no access to the Romania power market
- The national power network is divided into two systems, covering the right bank and the left bank of the Dniester River.
- Moldelectrica (located on the right bank) is officially the transmission system operator for both the left bank and the right bank, i.e., it ensures system dispatch, even though it does not control the left bank's transmission assets
- Only up to 25% of the Moldova's right bank electricity demand is met by the right bank generating plants. About 95% of that portion of demand (or approx. 24% of total right bank demand) is met by the old Combined Heat and Power (CHP) plants, whose power output must be bought at regulated prices well above the South Eastern Europe (SEE) power market prices. The remaining 5% is generated by the Costesti hydro power plant. The right bank CHP plants are dispatch based on heat load, and unable to operate as the network balancing reserve.
- Moldova right bank system for 75% of its electricity demand is dependent on imports of electricity from two sources: Ukraine and Moldova GRES (MGRES), a large power plant on the left bank of the Dniester River. This reflects the fact that Moldova's power system was designed as part of the former Soviet Union's IPS/UPS power system and has remained so to this date. The combination of expensive domestically produced power with relatively expensive imported power due to lack of effective interconnections to the Romanian system leaves Moldova with high priced electricity in the range of US$ 80/MWh (WB estimates).
- Power imports from Ukraine to the right bank system have decreased in recent years, and MGRES now accounts for virtually 100% of the imports. As a result, security of supply has become an even more urgent issue. If power production from MGRES decreases sharply or if the plant is

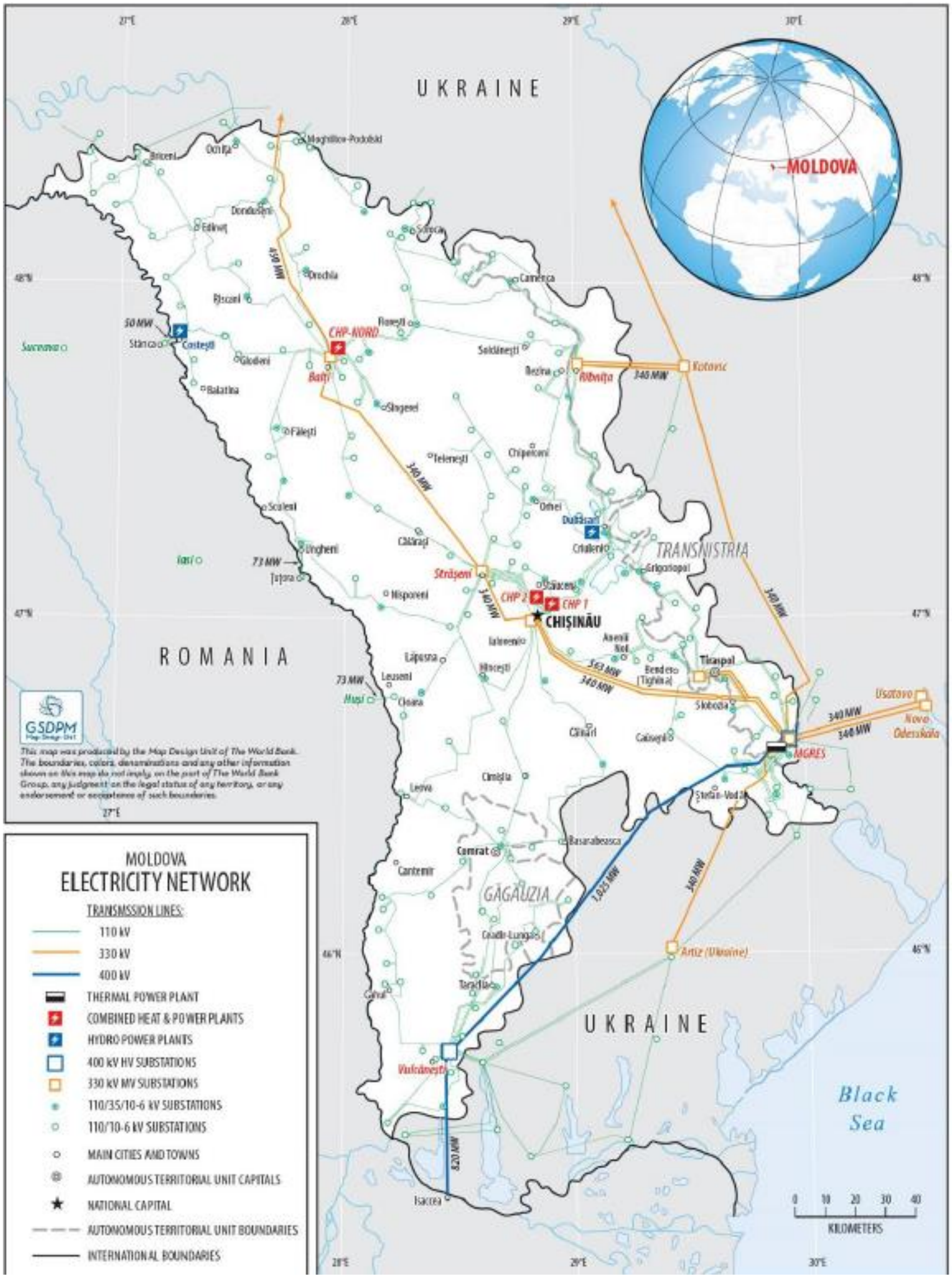
disconnected, massive load shedding will be necessary unless the shortfall can be covered by imports;

- Moldova's electricity system is synchronously interconnected with that of Ukraine, which is also part of the IPS/UPS system. Moldova system does not have a 400 kV connecting line to Ukraine system and the junction Moldova-Ukraine was not developed as a country-to-country interconnection. In fact, Moldova's network is used by the Ukrainian system to transfer electricity for its own purposes from north to south. This gives Moldova a leverage during power import price negotiations with Ukraine. An existing 400 kV line with Romania is not used for imports and not being maintained as Moldova and Romania power systems are not synchronized.
- Near-exclusive dependence on one source/supplier of natural gas. With the minor exception of hydropower, natural gas is currently the only fuel in the electricity generation mix. Not only all domestic CHPs, but also MGRES and to a lesser extent imports from Ukraine are dependent on Gazprom as gas supplier. Its transit and price determine security of supply and affordability of energy in Moldova.

The Left Bank has three operating power plants: MGRES, Dubasari HPP and Tirotex CHP. MGRES (owned by Inter RAO-UES) represents about 97% of the total installed capacity there and accounts for about 95% of total generation output. At present MGRES alone has enough installed capacity to meet Moldova's electricity demand.

Exhibit 96 shows Moldovan power transmission map with the main interconnectors.

Exhibit 96: Power Transmission Map of Moldova with main interconnectors



4.4.4 MOLDOVA GRID OPERATION WITH NEIGHBORING COUNTRIES

The Republic of Moldova shares borders with Romania to the west, and with Ukraine to the north and east. Moldova power network is connected to the Ukraine system. Electric energy exchange between Romania and Moldova is limited by an island operating mode because their electric power systems currently are not synchronized. During the 2001-2016 period, maximum electricity imports from the electric power system of Romania was up to 775 GWh/yr in 2008.

The electrical energy exchange between Ukraine and the Moldova is determined by the "control section", its maximum power being limited by the technical requirements of electric power system operational reliability. The control section includes: 4 x 330 kV OHLs, 3 x internal OHLs of Ukraine's national power system, 330 kV OHL Adjalîk - Usatovo 1, 330 kV OHL Adjalîk - Uasatovo 2 and the 330 kV OHL Ladîjenskaia CHP - Kotovsk; and a tie between Ukraine - Moldova, 330 kV OHL Hydroelectric power plant Dnestrovsk – Bălți.

The bulk of power transmission is accomplished by the mentioned above OHLs between Moldova, Ukraine and the Ukraine's region of Odessa that operate as import/export lines at the same time. Maximum power transmission values for the control section are determined by its carrying capacity, which depends significantly on the topology of 330 kV OHLs and the componence of those four electric power lines. Additional limiting factors include power generation by the Moldavskaya GRES (MGRES) and by the hydroelectric power plant Dnestrovsk. Therefore, due to the separation of the import/export areas on the OHL at the interstate boundaries, the allowable carrying capacity of the electrical energy imports from Ukraine to the electric power system of Moldova is the remnant value of the control section's transmission capacity, excluding interconnections with the region of Odessa. The maximum of electrical energy imports from the electric power system of Ukraine during the period of 2001-2016 was 2,960 GWh/yr in 2008.

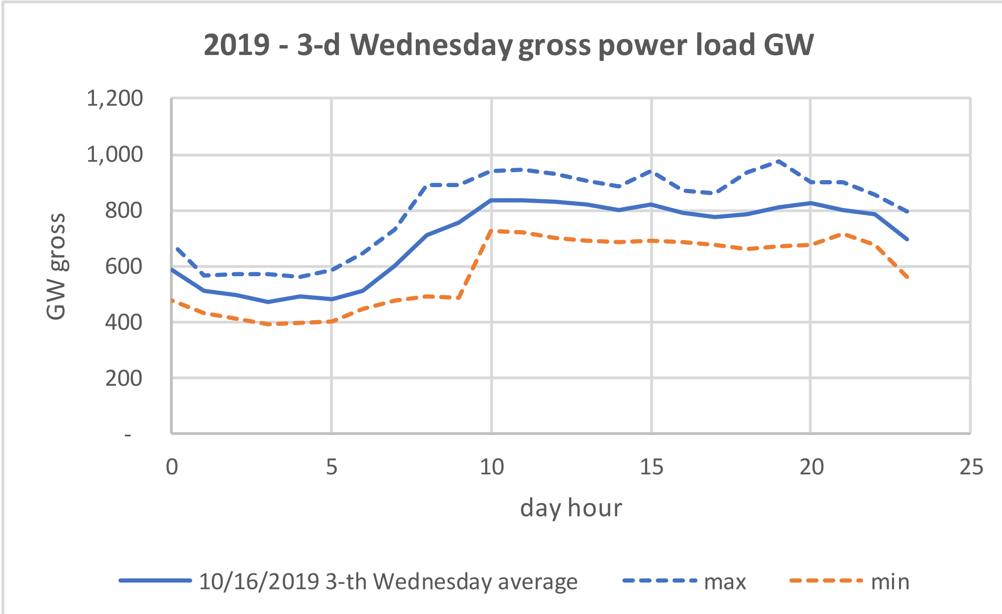
4.4.5 LOAD CHARACTERISTICS

The following load characteristics are utilized by Moldelectrica in their analysis to assure the network stability.

POWER LOAD THIRD WEDNESDAY

The gross power load on third Wednesday of every month presented in Exhibit 97 for 2019:

Exhibit 97: Third Wednesday of a month load curve for 2019



MAXIMUM, MINIMUM LOAD AND LOAD FACTOR

Annual maximum and minimum power loads and load factors for the right bank and the left bank power systems during 2007-2018 are presented in Exhibit 98.

Exhibit 98: Main System Load Characteristics

Load Characteristics	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Max Load MW	1157	1158	1146	1189	1082	1230	1115	1140	1028	1067	1030	1057
Min Load MW	344	334	299	327	269	275	316	327	337	309	307	329
Load Factor Hours	5,001	5,027	4,610	4,353	4,820	4,322	4,704	4,725	5,184	4,790	5,260	5,343

"STRESS DAYS"

"Stress Days" are the days when power network experienced extreme high or extreme low power loads. Historical "Stress Days" data for 2003-2015 is presented in Exhibit 99.

Exhibit 99 "Stress Days" of Moldova Power Network

Year	Winter Peak		Summer Peak		Low Load Day	
	Date & Time	P, MW	Date & Time	P, MW	Date & Time	P, MW
2003	11.01.03 18:00	1077	25.08.03 21:00	759	04.08.03 06:00	280
2004	17.12.04 19:00	1066	31.08.04 21:00	749	19.06.04 09:00	239
2005	11.02.05 19:00	1076	31.08.05 21:00	796	02.05.05 05:00	333
2006	24.01.06 21:00	1085	01.08.06 22:00	782	25.06.06 05:00	316
2007	14.12.07 19:00	1157	11.08.07 22:00	885	05.07.07 06:00	344
2008	10.11.08 09:00	1158	15.08.08 12:00	858	14.09.08 15:00	334
2009	16.12.09 18:00	1146	03.08.09 22:00	820	14.06.09 05:00	299
2010	15.02.10 14:00	1189	12.08.10 18:00	819	06.09.10 05:00	327
2011	05.01.11 18:00	1082	15.07.11 08:00	910	18.05.11 03:00	269
2012	13.11.12 13:00	1230	30.07.12 13:00	873	06.05.12 06:00	275
2013	11.12.13 18:00	1115	07.08.13 22:00	849	02.06.13 06:00	316
2014	03.12.14 18:00	1140	14.07.14 18:00	874	01.06.14 06:00	327
2015	26.01.15 19:00	1028	24.07.15 14:00	878	01.03.15 03:00	337

4.4.6 POWER DEMAND PROJECTIONS BY PREVIOUS STUDIES

The following recently completed assessments provide information on power demand projections and define the strategy for in-country power generation.

GOVERNMENT OF MOLDOVA

Moldovan government Decree "The Government Decision Nr. 102 dated 05.02.2013 [30] on the energy strategy of the Republic of Moldova up to the year 2030" stated that in 2030 the overall demand in Moldova will exceed 8,491 GWh/yr [31].

Exhibit 100: Government of Moldova forecast 2030 indicators

Indicators	**2015**	**2020**	**2025**	**2030**
GDP (current prices) billion lei	118.3	173.3	239,0	320.7
Industry (current prices) billion lei	49.5	67.9	92.5	121.3
Agriculture (in current prices) billion lei	27.1	32.9	40.1	48.9
Population, million	3.532	3.437	3.357	3.327
Total power demand GWh/yr	4,241	5,556	6,996	8,491

A forecast for an increase in consumer demand for electricity was revised to 5,396 GWh in 2030 in the later Moldova's energy strategy decree [32],

The main objectives for the national energy strategy in the Decree are defined as being consistent with the EU's policies and as follows:

- security of supply,

- competition and availability of affordable energy,
- environmental sustainability and combating climate change

The strategy declared that while it will be difficult for the Republic of Moldova to become an independent electric energy producer, for the reasons of security of power and heat supply the country shall consider an increase of in-country power generation as compared to 2012.

According to the government estimates,

- 32.5% of energy demand in 2030 should be covered by in-country generation.
- Electricity generation in the Republic of Moldova (not accounting Transdniestria) should be increased by a factor of 2.3 as compared to in-country generation in 2016, from 755 GWh to 1755 GWh in 2030.
- Production of electricity by cogeneration should increase by approximately 40% following the development of the CHP new capacities and growth and improvement of the district heating network operation in Chisinau.

WORLD BANK 2015

The World bank study [33] provides electricity demand and peak load forecast (Exhibit 101) based on Moldelectrica data and the Republic of Moldova Energy Strategy until 2033. The forecast in the study is based on the following assumptions:

- Electricity demand has been and is linearly correlated with Purchase Power Parity (PPP) GDP
- GDP growth rate of 3.26 %/year, which is equal to the average during 2001-2013
- Annual peak load occurs in the winter season (but gap between max and min is decreasing)
- Load factor will increase by 0.5 %/year due to increased use of air-conditioning, etc.
- Moldova Renewable Energy Sources (RES-E) with installed capacity of 150 MW, which is assumed to be equivalent base load capacity of 3 MW (2% of installed capacity)
- New 250 MW CHP-3 will be in operational in 2020.
- CET-Nord in Balti will maintain 20 MW capacity until 2033
- CET-1 and CET-2 will be retired in 2020

Exhibit 101: WB Power Demand Forecast

Year	GDP, Billion USD	Power Demand, GWh/yr	Peak Load, MW
2013	12.27	4,072	833
2014	12.67	4,170	849
2015	13.08	4,248	862
2016	13.51	4,328	873
2017	13.95	4,410	886
2018	14.41	4,496	898

Year	GDP, Billion USD	Power Demand, GWh/yr	Peak Load, MW
2019	14.88	4,584	911
2020	15.36	4,675	925
2021	15.86	4,769	939
2025	18.03	5,177	999
2030	21.17	5,766	1,085
2033	23.31	6,168	1,143

Estimated average annual growth in electricity demand 2.1% and in peak demand 1.6%. Other considerations:

- Import of power are still essential to address the Moldova demand – supply gap.
- Imports from Ukraine are likely to unable to cover Moldova's power deficit through 2033, as forecasts show that Ukraine will not to be able to satisfy its own peak demand starting in 2018.
- Imports from MGRES to fully cover Moldova's power deficit beyond 2020 is questionable, as significant investments needed to keep the current MGRES capacity operating.
- Imports from Romania are expected at about 3,300 MW at any time during 2020 – 2033 (even excluding Romania's 4,500 MW renewable energy sources capacity)

Considering the above, World Bank forecasts that assuming a new 250MW CHP is commissioned in 2020, replacing the CET-2 now in use, there will be still a projected deficit of approx. 700 – 800 MW after year 2030.

It should be noted that some of the assumption in the WB study forecast are no longer valid. That is, a new 250MW CHP will not be commissioned and CET-2 will not be retired in 2020. The most probable schedule for these events to occur is circa 2030.

The WB study peak demand-supply forecast in Exhibit 102 shows that by 2030 Moldova will have a supply deficit of 812 MW during the periods of peak power demand.

Exhibit 102: WB Peak Demand-Supply Forecast, MWe

Year	**2012**	**2013**	**2015**	**2019**	**2020**	**2025**	**2030**	**2033**
Annual Peak Load Demand	831	833	862	911	925	999	1,085	1,143
Domestic Generation	247	209	222	222	273	273	273	273
CHP-1	25	27	0	0	0	0	0	0
CHP-2	202	162	202	202	0	0	0	0
CHP-3	0	0	0	0	250	250	250	250

Year	2012	2013	2015	2019	2020	2025	2030	2033
CHP-Nord	20	20	20	20	20	20	20	20
RES-E	0	0	0	0	3	3	3	3
TOTAL Deficit	584	624	640	689	652	726	812	870
Covered by MGRES	399	438	550	400	TBD			
Covered by imports from Ukraine	185	186	90	289	TBD			

To bridge the deficit gap, the study recommends implementing an asynchronous link between Moldova and Romania national power networks, the two power systems with different frequency standards through back-to-back stations, enabling Moldova interconnection with ENTSO-E network, while remaining in IPS/UPS system. Romania is considered as a potential source of power to satisfy the forecasted deficit.

KEY FINDINGS FROM THE PREVIOUS FORECASTS

All the reviewed sources agree that:

- A substantial deficit in Moldova power generation in expected for the forecasted period through 2030 and that the import of electric power will be required to meet the projected power demand.
- Natural gas is a fuel of choice for the future new fossil power plants.
- Part of the new generation will be based on renewable sources of energy (up to 400 MW).
- 32.5% of energy demand in 2030 should be covered by in-country generation.
- The future new fossil power plants should utilize a CHP cycle.

There is a notable variation between the reviewed sources in the annual electricity demand forecasts in 2030-33 for the Moldova right bank energy region as summarized in Exhibit 103, with the forecasts completed at a later date projecting increasingly lower annual power demand.

Exhibit 103 Summary of Annual Power Demand Forecasts

Source	Power Demand, GWh/y	% Difference
Strategy 2018 – 2030	5,400	0
World Bank 2015	6,200	15%
Strategy 2013	8,500	57%

4.4.7 POWER DEMAND FORECAST

ASSUMPTIONS AND APPROACH USED FOR DEMAND PROJECTION

The demand forecast approach used in this study is based on 2003-2017 historical Moldova's net electricity consumption by a sector of economy. It was calculated by extrapolating growth in Moldova's Purchasing Power Parity (PPP) GDP and net electricity demand during the same period. The evolution of the country's effective PPP GDP is based on reports from the Ministry of Economy and Infrastructure of the Republic of Moldova, Department of Macroeconomic Analysis and Forecasts, World Bank, and EBRD estimates. The country's net electricity consumption is based on ANRE report [34], Moldelectrica SA and Termoelectrica SA data. Historical electricity demand data by sector of economy is summarized in Exhibit 104:

Exhibit 104: Power demand forecast input data, GWh/yr

Year	IND	CONSTR	TRANSP	AGR	COMM	HH	Other	Total Demand	Power Purchased ANRE	HV, LV Losses
2003	865	8	51	52	581	836	134	2,527	3,364	25%
2004	871	10	47	48	539	964	155	2,634	3,255	19%
2005	974	10	50	51	671	1,041	124	2,921	3,465	16%
2006	1,026	14	58	55	753	1,154	155	3,215	3,660	12%
2007	1,049	15	65	50	745	1,295	145	3,364	3,827	12%
2008	948	14	62	54	841	1,371	138	3,428	3,860	11%
2009	872	13	50	59	866	1,450	68	3,378	3,800	11%
2010	975	13	46	54	783	1,514	101	3,486	3,921	11%
2011	992	14	50	54	821	1,547	93	3,571	3,999	11%
2012	826	12	47	47	977	1,570	-	3,477	4,055	14%
2013	872	12	58	58	953	1,616	-	3,570	4,079	12%
2014	895	12	58	47	977	1,663	-	3,651	4,130	12%
2015	756	6	58	47	1,151	1,674	-	3,692	4,153	11%
2016	744	12	70	47	1,128	1,628	-	3,628	4,101	12%
2017	756	12	81	47	1,163	1,640	-	3,698	4,159	11%

Legend:

IND – Industrial	CONSTR – Construction	TRANSP – Transportation	AGR – Agricultural
COMM – Commercial	HH - Households	HV – High Voltage	LV – Low Voltage

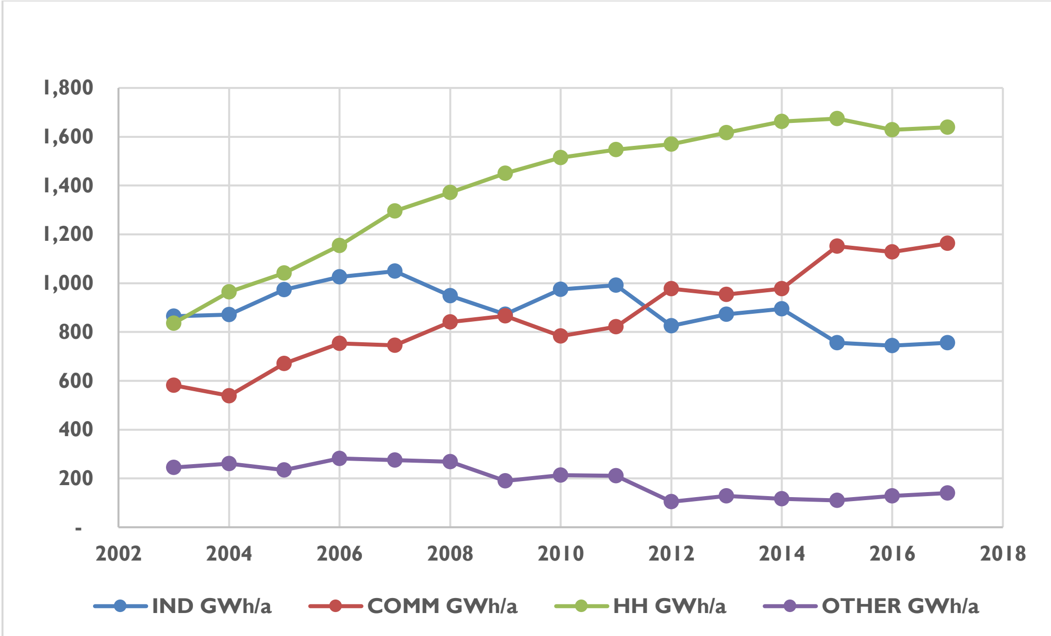
The Household, Commercial and Industrial sectors are by a wide margin the largest consumers of electricity in Moldova. Electricity consumption by all other economy sectors in Exhibit 103 is combined into a common group.

Exhibit 105: Power Demand by Sectors of economy 2003-2017, GWh/yr

Year	IND	COMM	HH	Other	Total
2003	865	581	836	245	2527
2004	871	539	964	260	2634
2005	974	671	1,041	235	2921
2006	1,026	753	1,154	282	3215
2007	1,049	745	1,295	275	3364
2008	948	841	1,371	268	3428
2009	872	866	1,450	190	3378
2010	975	783	1,514	214	3486
2011	992	821	1,547	211	3571
2012	826	977	1,570	105	3477
2013	872	953	1,616	128	3570
2014	895	977	1,663	116	3651
2015	756	1,151	1,674	110	3692
2016	744	1,128	1,628	128	3628
2017	756	1,163	1,640	140	3698

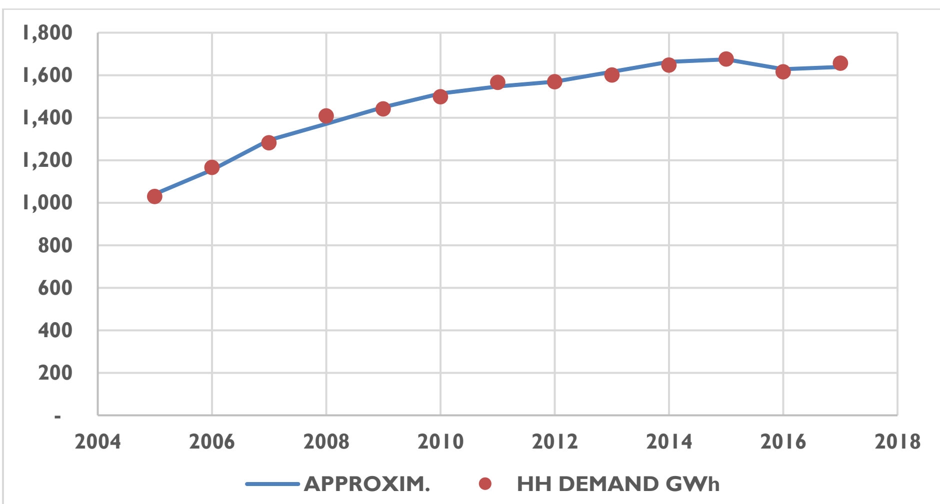
Progression of power demand (right bank) by sector of economy during 2003-2017 is illustrated in Exhibit 106.

Exhibit 106: Power Demand Progression (2003-2017)



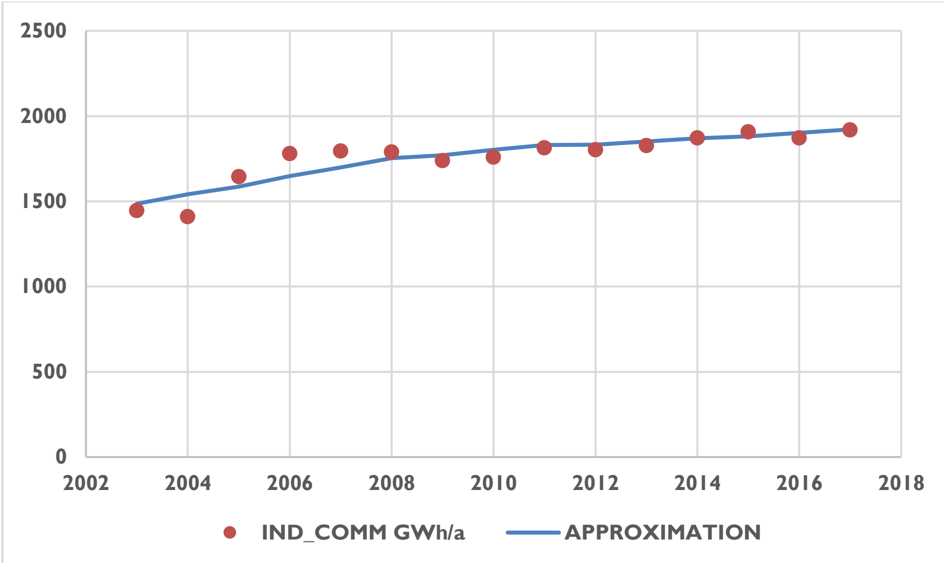
Trend analysis reveals that the historical electricity demand by the household sector, which has the biggest share in demand, has a relatively close correlation with the historical GDP PPP in 2010 USD, total Moldova population numbers and the quantity of dwellings in the country. This correlation can be expressed as an approximation (R^2~0.99) and is presented in Exhibit 107.

Exhibit 107: Household power demand approximation, 2005-2017, GWh/yr



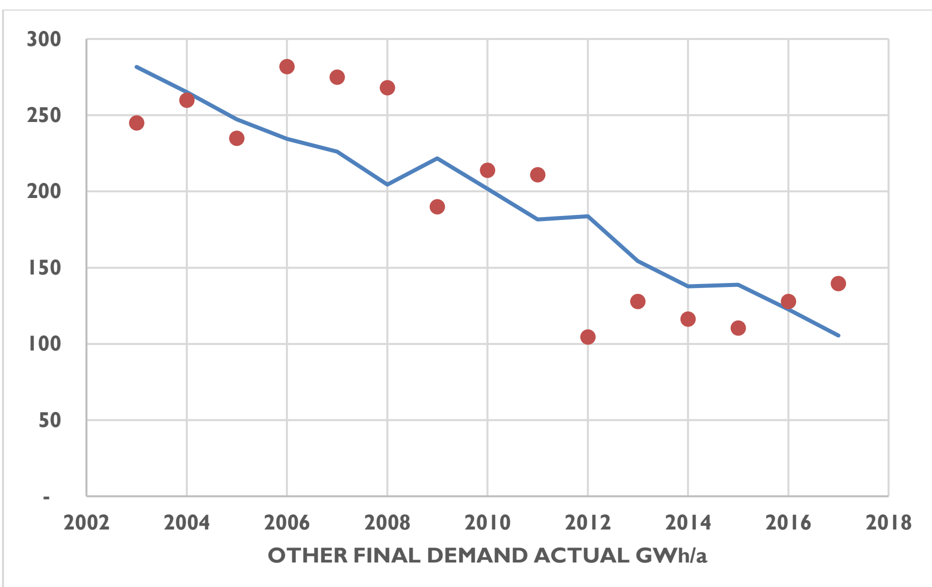
Historical trend of the electricity demand by the industry and commercial sectors also correlated well with the historical GDP PPP in 2010 USD, total Moldova population numbers and the quantity of dwellings in the country. This correlation can be expressed as an approximation (R^2~0.82) and is presented in Exhibit 108.

Exhibit 108: Industry and Commercial power demand approximation, 2003 – 2017, GWh/yr



Historical trend of the demand by the remaining other sectors somewhat correlates with the historical GDP PPP in 2010 USD, total Moldova population numbers and the quantity of dwellings in the country. For this sector, the correlation can be approximated as (R^2~0.65), which is consistent with the historical reduction in power demand by other sectors at a rate of approximately 100-150 GWh/yr as shown in Exhibit 109:

Exhibit 109: Other power demand approximation, 2003 – 2017, GWh/yr



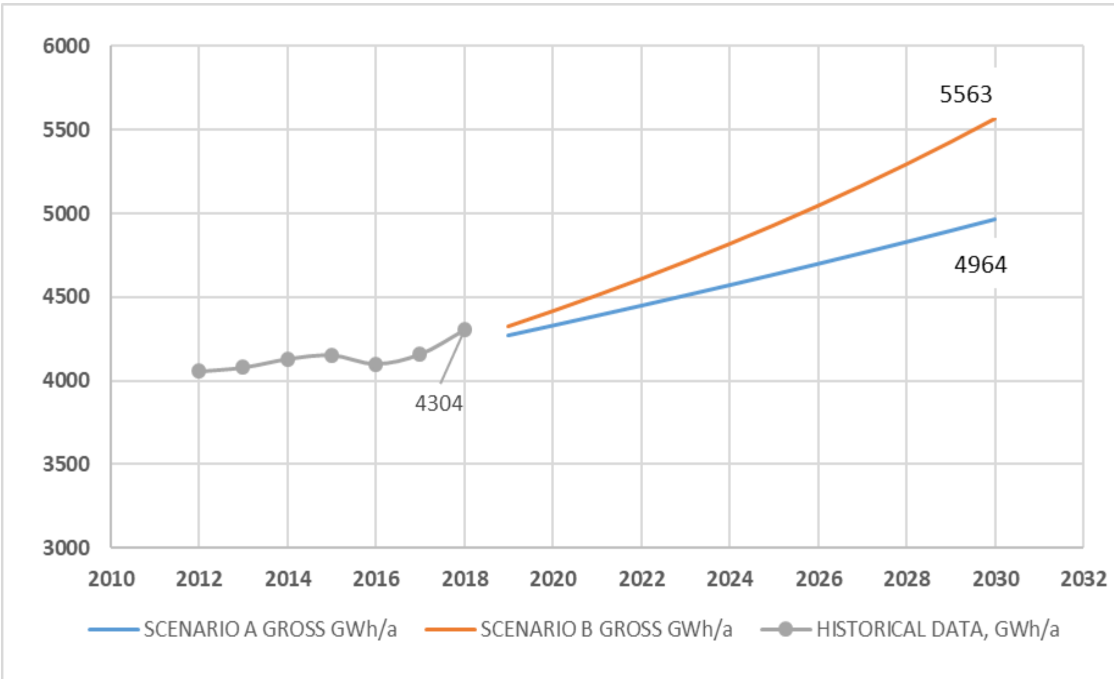
MOLDOVA POWER DEMAND FORECAST 2030

The future power demand forecast is developed utilizing the above approximations for the following range of the assumed scenarios of the future annual GDP PPP growth rates:

- Scenario A at 3% annual growth,
- Scenario B at 6% annual growth

The net values of the forecasted electricity demand are adjusted to include expected HV and LV losses. The gross electricity demand forecast (including losses) for the right bank power system is presented in Exhibit 110.

Exhibit 110: Moldova Right bank gross electricity demand forecast through 2030, GWh/yr



Comparisons of Scenario A and Scenario B projections with the past studies is presented in Exhibit 111.

Exhibit 111 Comparison of electricity demand projections for 2030r

Source	Power Demand, GWh/y	% Difference
Strategy 2018 – 2030	5,400	0
World Bank 2015	6,200	15%
Strategy 2013	8,500	57%
Scenario A	4,964	-8%
Scenario B	5,563	3%

The range of gross electricity demand projections in Scenarios A and B is consistent with the Moldovan government forecast for 2018-2030, and somewhat lower than the WB forecast in their 2015 study.

PEAK LOAD FORECAST

Historical operating data provided by SE Moldelectrica for the right bank system is presented in Exhibit 112

Exhibit 112: 2012-2018 Right Bank electric power and load

Year	Power, GWh/yr Gross				Gross Load, MW Gross		Load factor, hours
	Total	MGRES	Right Bank Generated	Imported	Peal Load	Min Load	
2012	4055	2433	776	846	941	268	4,309
2013	4079	1876	748	1456	833	248	4,898
2014	4130	2611	788	731	811	244	5,093
2015	4153	3342	793	18	754	258	5,511
2016	4101	3343	755	4	786	245	5,219
2017	4159	2279	747	1133	730		5,697
2018	4304	2544	804	956	966		4,455

Peak load forecast in Exhibit 113 is developed based on the Scenario A and B of the gross electricity demand projections (Exhibit 110) and an assumed escalation of 0.5% a year of the historical load factors provided by SE Moldelectrica and ANRE.

Exhibit 113: Peak load forecast for 2020-2030

Year	Scenario A		Scenario B	
	Gross Power, GWh/yr	Peak Load, MW	Gross Power GWh/yr	Peak Load MW
2020	4,330	837	4,418	854
2021	4,389	844	4,512	868
2022	4,449	851	4,610	882
2023	4,510	858	4,712	897
2024	4,571	866	4,818	913
2025	4,634	873	4,929	929
2026	4,698	881	5,045	946
2027	4,763	889	5,166	964
2028	4,829	897	5,292	983
2029	4,896	904	5,425	1,002
2030	4,964	912	5,563	1,023

5 TASK 3: GAS AND WATER SUPPLY

5.1 INTRODUCTION

This section provides results of the following tasks related to availability and forecast of natural gas and raw makeup water for the new generation capacities in Moldova.

1. Based on available information provide a current summary and a forecast of gas supply availability from all the potential sources,
    a. Summary of historical (at least 3 years) gas consumption, separately for all user categories in Moldova.
    b. The availability of gas quantities in seasonal high and low regimes,
    c. Gas pressures available for power generation.
    d. Any required/considered technical improvements to the gas supply network.
    e. Summary of all potential risks related to the gas supply availability, with the acceptable level of certainty.
2. The availability, reliability, quantity and quality of technical water for the new generation capacity, considering all reasonably available sources, technologies and storage capacity, and
3. The need for water supply system improvements and estimate of required investments.

In addition, this section provides summary of a regional gas supply availability, and available capacities in close proximity to Moldova such as the South East European (SEE) gas supply network and the possibilities for diversification of gas supply to Moldova, including:

- Availability of natural gas
- Availability of LNG imports in future
- Planned and under development SEE gas pipelines

5.2 EXISTING SOURCES OF NATURAL GAS SUPPLY

Currently all the natural gas consumed in Moldova is being imported from Russia in accordance with a contract that was signed in 2008. The contract is being extended on an annual basis, and it links gas prices for Moldova to the global market prices. An alternative source of natural gas supply to Moldova from Romania is being developed by Vestmoldtransgaz via the Iasi-Ungheni-Chisinau pipeline.

Major natural gas companies in Moldova include Moldovatransgaz, Moldovagas, and Vestmoldtransgaz. Their descriptions are provided in the following sections.

5.2.1 MOLDOVATRASNGAZ

Moldovatransgaz is an operator of natural gas transmission system in Moldova (Exhibit 115). Moldovatransgaz is one of the main companies that provides transit of Russian natural gas to the Balkan countries (Romania, Bulgaria, Turkey), and to the natural gas customers in Moldova, and some of the customers in Ukraine, near the Moldovia border. Moldovatransgaz consists of 4 compression stations located in Drochia, Chisinau, Vulcanesti, and Goldanesti with total of more than 600 employees. [35].

5.2.2 MOLDOVAGAZ

Moldovagaz is one of the largest enterprises in the energy sector of Moldova. The main activity of the company and its subsidiaries is transmission, distribution and supply of natural gas in Moldova. The company has over 690,000 customers in the country. Moldovagaz supplies natural gas thru its existing contractual relation with Gazprom. The transmission services are performed via Moldovagaz service contract with Moldovatransgaz. Distribution of the natural gas to its final customers is performed by the twelve Moldovagaz subsidiaries. [36].

5.2.3 VESTMOLDTRANSGAZ

Vestmoldtransgaz was registered in 2014 as a state-owned company, with the purpose to build, operate and maintain the Iași - Ungheni natural gas pipeline. The company is licensed to ensure operation, maintenance and management, as well as expansion, development and efficiency improvement of the existing natural gas transport infrastructure, and to facilitate interconnection of the Iași - Ungheni natural gas pipeline with the neighboring natural gas transportation systems. The Vestmoldtransgaz natural gas transportation system is designed to operate at 55 bar pressure to support the natural gas import from Romania. In 2016 Vestmoldtransgaz started a project for construction of the natural gas transport network from Ungheni to Chisinau (DN600, PN 5.5MPa, L=120 km) with two pressure regulation and metering stations located in Chisinau area, and an interconnection station located in Semeni locality of the Ungheni district. The project design was performed by Transgaz of Romania. Currently Vestmoldtransgaz is owned by Eurotransgaz, a Transgaz company of Romania. This acquisition occurred in 2018. [37]

5.3 MOLDOVA NATURAL GAS INFRASTRUCTURE

5.3.1 EXISTING NATURAL GAS INFRASTRUCTURE

Before the Iasi-Ungheni pipeline construction in 2014 (Exhibit 114), the Moldova natural gas transport network was a one direction flow and single supply source type system. The gas pipelines ATI, RI, SDKRI (Exhibit 114) and CS Vulcanesti (Exhibit 115) provide transportation of natural gas to the Balkan countries, and the customers in southern Moldova. The ACB pipeline (Exhibit 114) and CS Drochia pipeline (Exhibit 115) provide the transit of natural gas to the underground gas storage facility of Bogorodchany, Ukraine (Exhibit 114), and gas supplies to the customers in central and northern Moldova. In 2007 Tokuz-Kainary-Mereny pipeline in Southern Moldova (Exhibit 115) with total length of 62.74 km was completed.

Exhibit 114 Natural gas pipelines thru Moldova, by ENTSOG

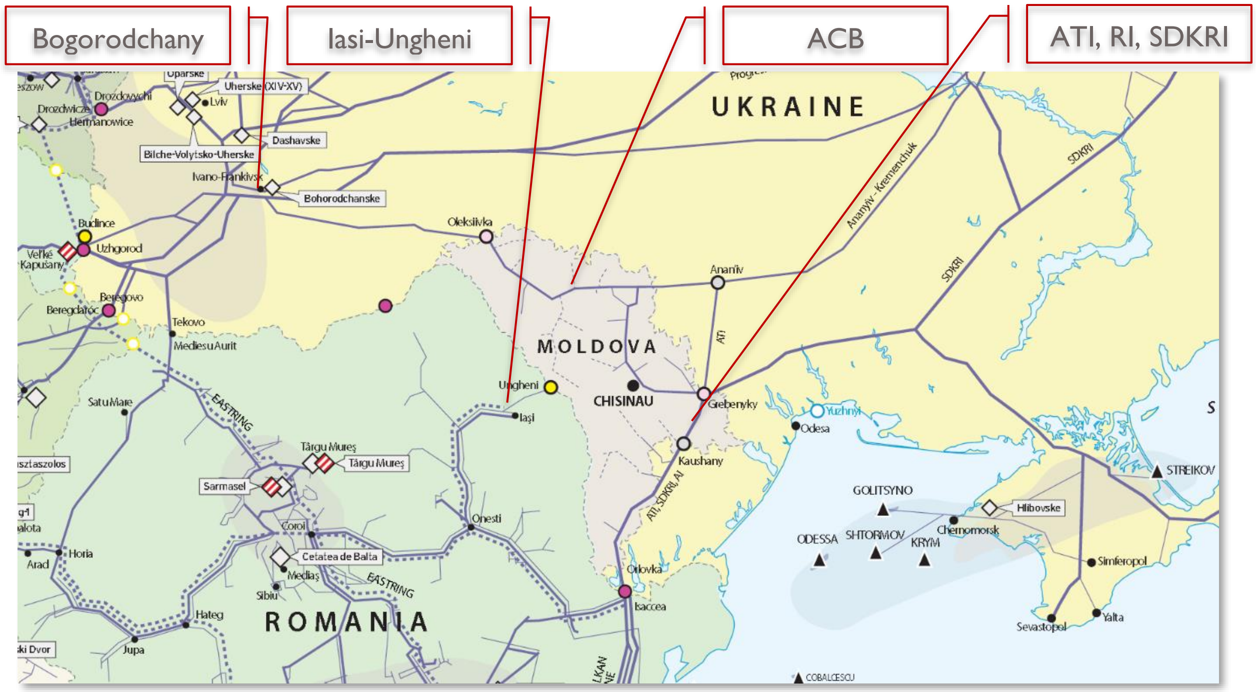
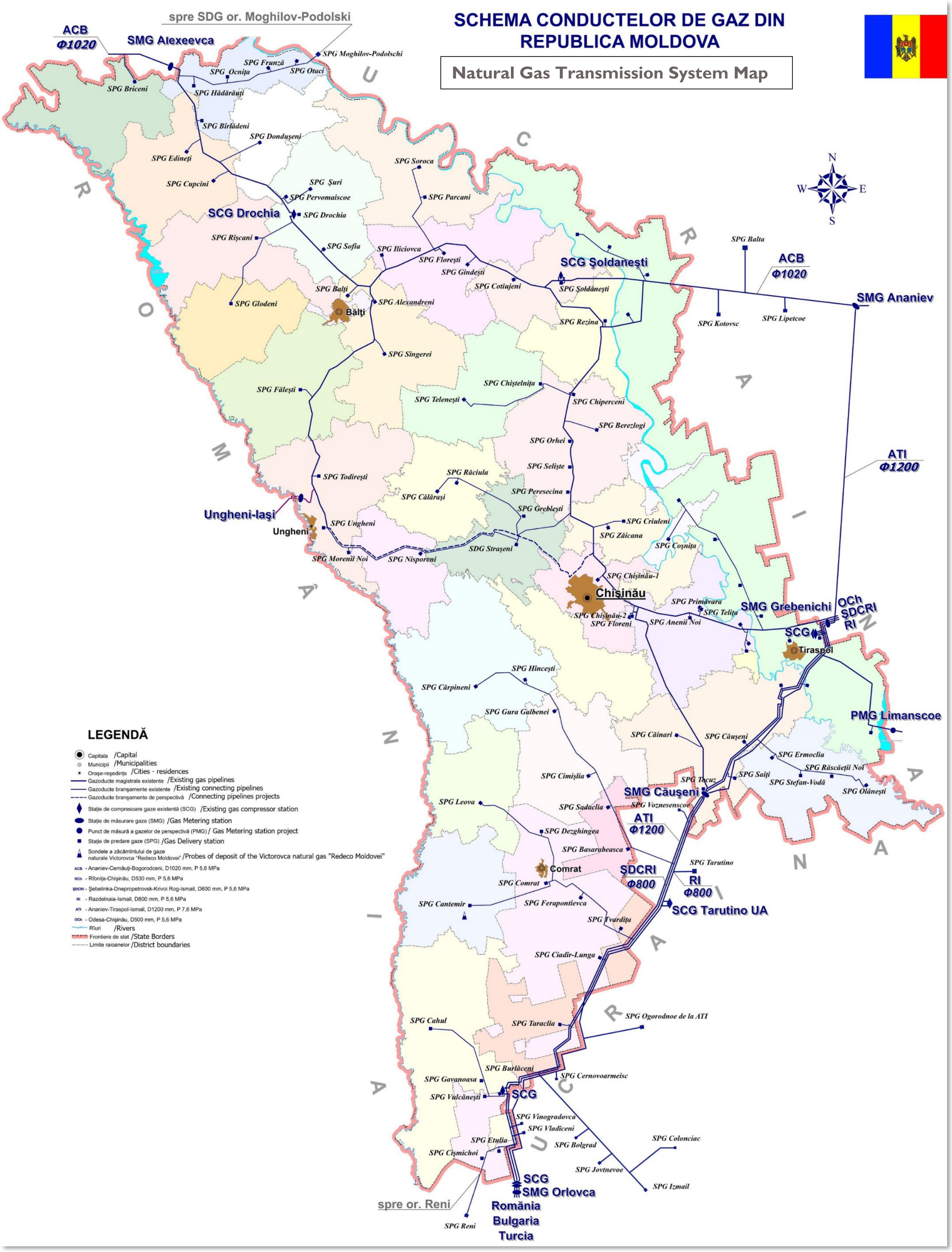


Exhibit 115 Moldova natural gas transmission and distribution lines, by Moldovatransgaz



Key parameters of the Moldovatransgaz infrastructure (Exhibit 115) are presented in Exhibit 116. Appendix A provides details on entry/exit points of Moldovatransgaz network.

Exhibit 116 Key Natural Gas Infrastructure of the SRL Moldovatransgaz (2018)

SYSTEM COMPONENT	PARAMETER	CAPACITY
Main pipelines, total length	656.25 km	-
Ananiev-Tiraspol-Ismail (ATI), DN1200, PN 7.5MPa	62.91 km	20 bcma
Razdelinaia-Ismail (RI), DN800, PN 5.5MPa	92.2 km	7.3 bcma
Sebelinca-Dnepropetrovsk-Krivoi Rog-Ismail (SDKRI), DN800, PN 5.5MPa	91.8 km	7.3 bcma
Ananiev-Cernauti-Bogorodciani (ACB), DN1000, P 5.5MPa	184.8 km	9.1 bcma
Chisinau-Rabnita (ChR), DN500, PN 5.5MPa	91.1 km	1.5 bcma
Odessa-Chisinau (OCh), DN500, PN 5.5MPa	44.0 km	1.3 bcma
Tocuz-Cainari-Mereni (TCM), DN500, PN 5.5MPa	62.7 km	1.8 bcma
Oliscani-Saharna (OlS), DN500, PN 5.5MPa	26.7 km	-
Branch pipelines total length	903.4 km	-
Gas compression stations:		
CS Drochia, 5xGPA-T-6.3V, Aviation engine	HK-12ST	31.5 MW
CS Vulcanesti, 5xGPA-STD-4000	electric motor	20.0 MW
CS Soldanesti, 6xGPA-STD-4000-2	STD-4000-2	24.0 MW
Causeni gas metering station	1	32 bcma
GRS stations (pressure reducing stations)	80	
Cathodic protection stations	221	
Cable lines for technological telecommunications	1914.9 km	

Vestmoldtransgaz operates the infrastructure as shown in Exhibit 117. The solid red line in Exhibit 117 represents the Iasi-Ungheni pipeline, and the dashed red line is Ungheni - Chisinau pipeline currently under construction.

Exhibit 117 Vestmoldtransgaz operating infrastructure, by Vestmoldtransgaz

5.3.2 IN COUNTRY GAS RESERVES AND PRODUCTION

Moldova is reported to have no proved commercially recoverable natural reserves [1]. Moldova completely relies on natural gas imports.

5.4 COUNTRY-WIDE NATURAL GAS CONSUMPTION

Country-wide natural gas consumption presented in this section is a summary of the data reported by ANRE and the National Bureau of Statistics of Moldova. The consumption is presented by year and by user categories.

5.4.1 GAS CONSUMPTION BY YEAR

The natural gas market in Moldova is monitored by ANRE. Data presented in Exhibit 118 is a summary based on ANRE annual reports for the years 2014 through 2018. The 2019 data is not included, as the ANRE report for 2019 was not completed at the time of writing of this report.

Exhibit 118 Summary of Moldova Natural Gas consumption for 2014-2018 period, by ANRE

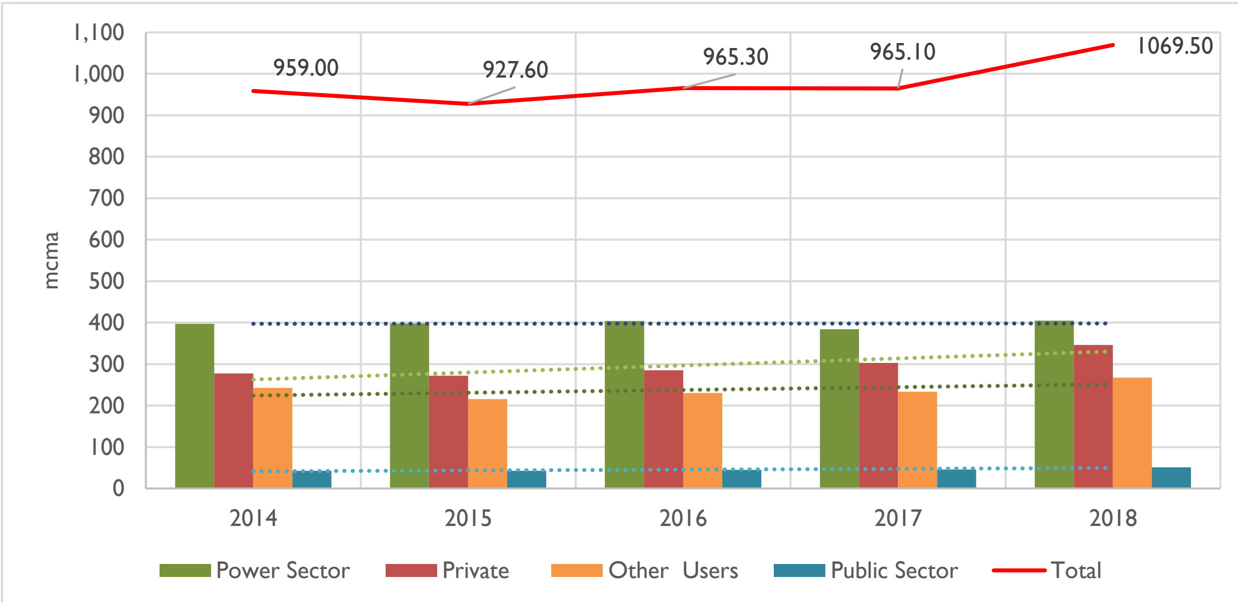
PARAMETER	UNITS	2014	2015	2016	2017	2018
TOTAL DELIVERED NATURAL GAS	mcma	959.00	927.60	965.30	965.10	1069.50
	Million MDL	5867.30	5794.00	5873.50	5762.40	5384.60
	MDL/1000m3	6118.00	6246.00	6085.00	5971.00	5035.00

PARAMETER	UNITS	2014	2015	2016	2017	2018
BY USER						
PRIVATE SECTOR	mcma	277.10	271.60	285.30	302.80	346.40
	Million MDL	1832.60	1834.10	1902.90	1978.80	1808.40
	MDL/1000m3	6613.00	6754.00	6670.00	6535.00	5221.00
	% of total	28.90	29.30	29.60	31.40	32.40
PUBLIC SECTOR	mcma	42.70	42.70	45.10	45.40	51.20
	Million MDL	277.10	284.10	300.40	293.40	294.30
	MDL/1000m3	6494.00	6652.00	6655.00	6463.00	5754.00
	% of total	4.40	4.60	4.70	4.70	4.80
POWER GENERATION SECTOR	mcma	396.90	398.10	404.30	384.00	404.90
	Million MDL	2245.10	2304.60	2247.40	2073.50	1942.30
	MDL/1000m3	5657.00	5789.00	5559.00	5400.00	4797.00
	% of total	41.40	42.90	41.90	39.80	37.90
OTHER USERS	mcma	242.30	215.30	230.50	233.00	267.10
	Million MDL	1512.60	1371.20	1422.80	1416.70	1339.60
	MDL/1000m3	6243.00	6370.00	6171.00	6081.00	5015.00
	% of total	25.30	23.20	23.90	24.10	25.00

Legend:
mcma – million normal cubic meters per annum
MDL - Moldovan leu

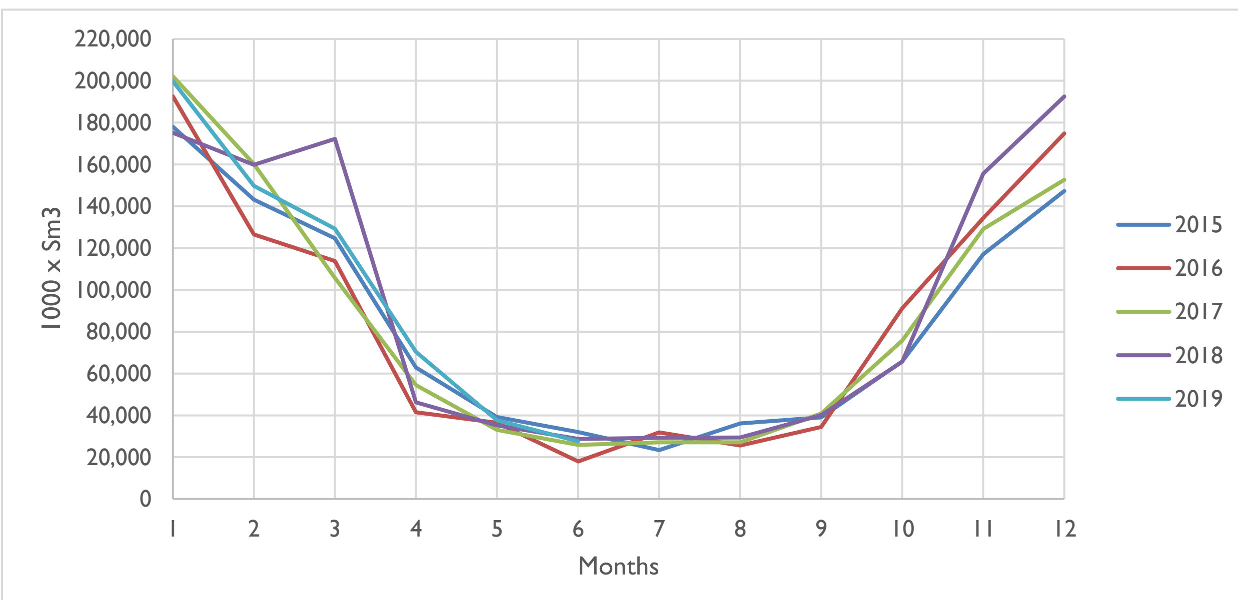
The graphic representation of the Exhibit 118 data in Exhibit 119 illustrates that the overall gas consumption in the county increased during the reported period by approximately 11%, mainly due to increased consumption by the "Private Sector" and "Other Users" categories. Natural gas consumption in the Power and Public Sectors remained relatively constant during the reported period.

Exhibit 119 Natural gas consumption by sectors for 2014-2018, by ANRE



A summary of natural gas imports to Moldova by month during 2015 through the first half of 2019 is presented in Exhibit 120 [38].

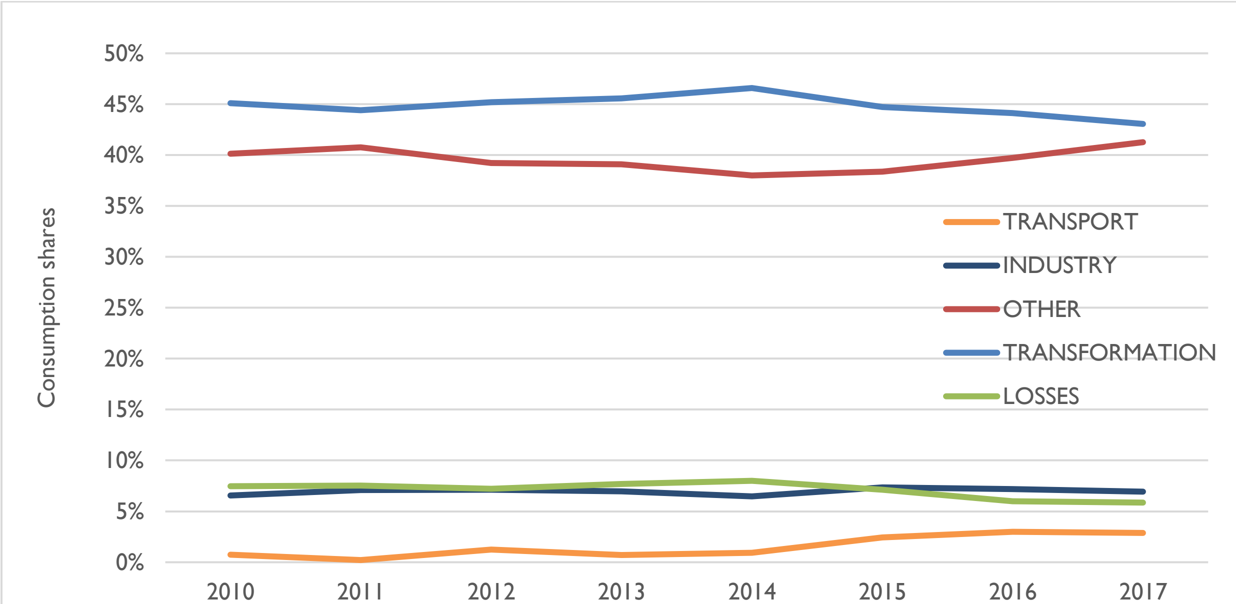
Exhibit 120 Natural gas imports, by National Bureau of Statistics of Moldova



5.4.2 GAS CONSUMPTION BY INDUSTRY

A country-wide natural gas consumption by various groups of industries and non-industrial consumers by year is presented in Exhibit 121. Moldova Energy Balance provides summaries by consumer in few major sectors of the country economy.

Exhibit 121 Moldova natural gas consumption by sector of economy, National Bureau of statistics Moldova



The Energy Transformation sector (includes industries where one type of energy is converted to another type of energy, such as natural gas to electricity) holds the largest share of the natural gas consumption. This sector includes CHP, heat only and power only plants, where CHP plants are the biggest consumers with approximately 33% of the total consumed natural gas in Moldova.

The Other sector, comprising residential, agricultural, and other consumers is the second largest group, where residential consumers hold approximately 29% from the total natural gas consumed in Moldova.

The Industry sector comprises all the industrial consumers, where its largest consumer is the non-metallic minerals industry with 4% in average from the total natural gas consumed in Moldova.

The Transportation sector is the smallest consumer group, where the largest consumer is pipeline transportation with less than1% in average from the total natural gas consumed in Moldova.

Losses not presented in the information above are approximately 7% on average from the total natural gas consumed in Moldova.

5.5 FORECAST OF MOLDOVA NATURAL GAS CONSUMPTION

Moldova's natural gas consumption is expected to follow its national GDP trend. Moldova's historical GDP in comparison with the neighboring Bulgaria, Hungary, Romania and Ukraine is presented in Exhibit 122. Moldova's annual GDP % change and historical GDP per capita are presented in Exhibit 123.

Exhibit 122 Moldova Historical GDP compared to neighboring countries, % change per capita

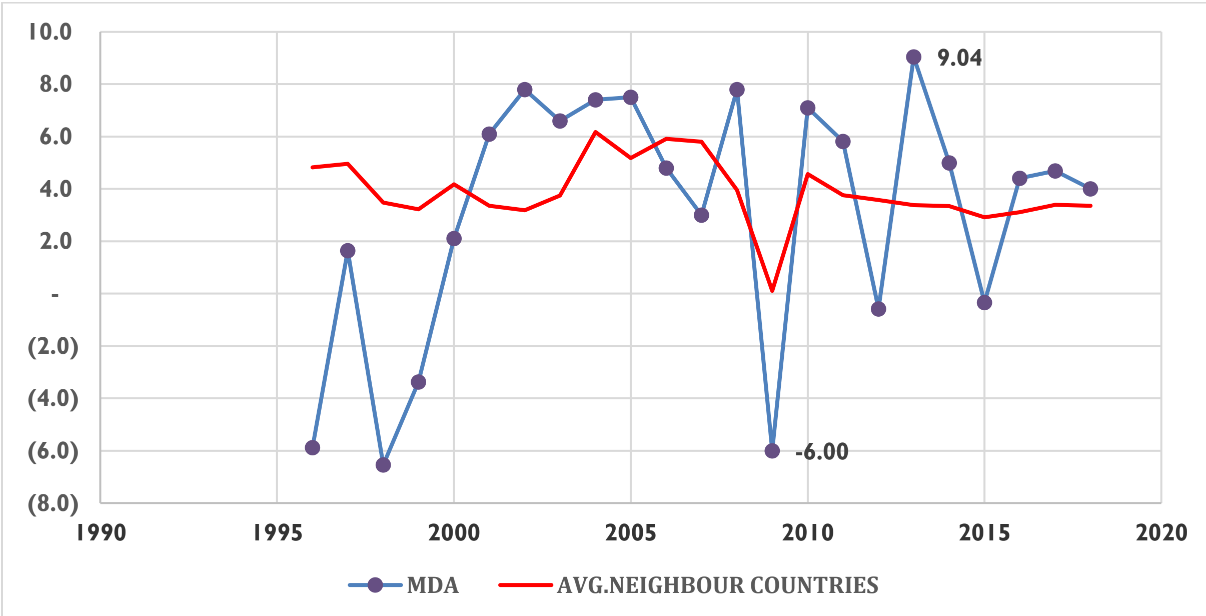
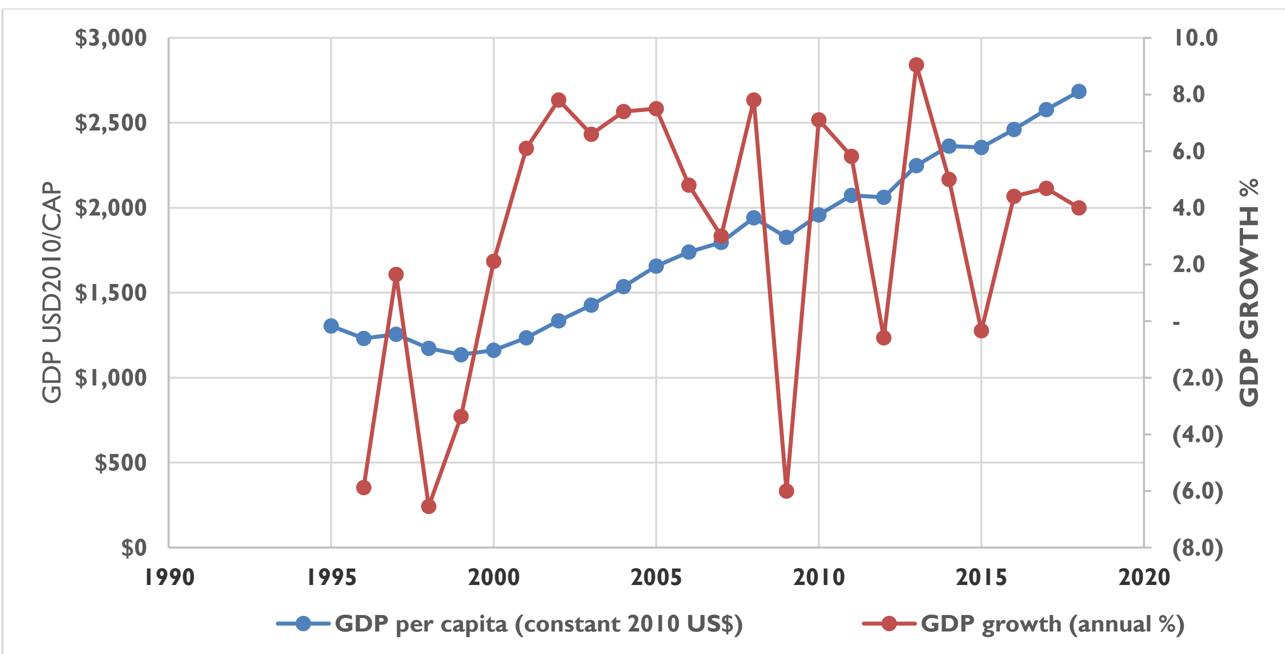


Exhibit 123 World Bank macro-economic data Moldova 1995-2018



Historical correlation of the Moldova GDP per capita, population and the natural gas consumption by major consumers groups is presented in Exhibit 124.

Exhibit 124 Moldova Macro-economic data

YEAR	Population, millions	GDP per capita (constant 2010 USD)	GDP change (annual %)	PRIVATE, MCM/yr	OTHER MCM/yr	POWER MCM/yr	PUBLIC MCM/yr	Total MCM/yr
2014	3.56	2,362	5.0%	277	242	397	45	961
2015	3.56	2,356	-0.3%	272	215	398	43	928
2016	3.55	2,461	4.4%	285	231	404	45	965
2017	3.55	2,578	4.7%	303	233	384	45	965
2018	3.55	2,684	4.0%	346	267	405	50	1,068

Estimation of the natural gas demand forecast for the Private, Other and Power consumer groups is performed using statistical analysis that considered historical data provided in Exhibit 124 and per the following equation:

DEMAND= CONSTANT+C*POPULATION+B*GDP+A*GDP growth

Where the constants are:

	A	**B**	**C**	**Constant**
PRIVATE	0.46665	-427.0444	10,025.453	(36,470.71)
OTHER	0.43409	-191.4539	13,717.107	(49,573.91)
POWER	0.00824	-66.5560	150.387	(154.83)

An average of 4.6% of the total demand was assumed for the Public consumer group.

The following range of the assumed scenarios of the future annual GDP growth is consistent with the power demand forecast scenarios in Section 4.4.7:

- Scenario A at 3% annual growth,
- Scenario B at 6% annual growth

Natural gas demand forecast corresponding to the Scenario A of GDP growth is presented in Exhibit 125.

Exhibit 125 Natural Gas Demand Corresponding to the Scenario A of GDP Growth.

Year	Population, million	Natural Gas Demand at 3% GDP annual Growth, million cubic meters a year				
		Private	Other	Power	Public	Total
2014	3.56	277	242	397	43	959
2015	3.56	272	215	398	43	928
2016	3.55	285	231	404	45	965
2017	3.55	303	233	384	45	965
2018	3.55	346	267	405	51	1,070
2019	3.55	362	268	399	50	1,079
2020	3.54	378	274	399	51	1,103
2021	3.54	396	281	399	52	1,129
2022	3.54	415	289	399	54	1,157
2023	3.54	435	298	399	55	1,188
2024	3.54	457	308	399	57	1,221
2025	3.53	480	320	399	58	1,257
2026	3.53	504	333	399	60	1,296
2027	3.53	530	347	399	62	1,338
2028	3.53	556	362	399	64	1,382
2029	3.52	585	379	399	66	1,430
2030	3.52	615	397	399	69	1,480

Natural gas demand forecast corresponding to the Scenario B of the GDP growth is presented in Exhibit 126

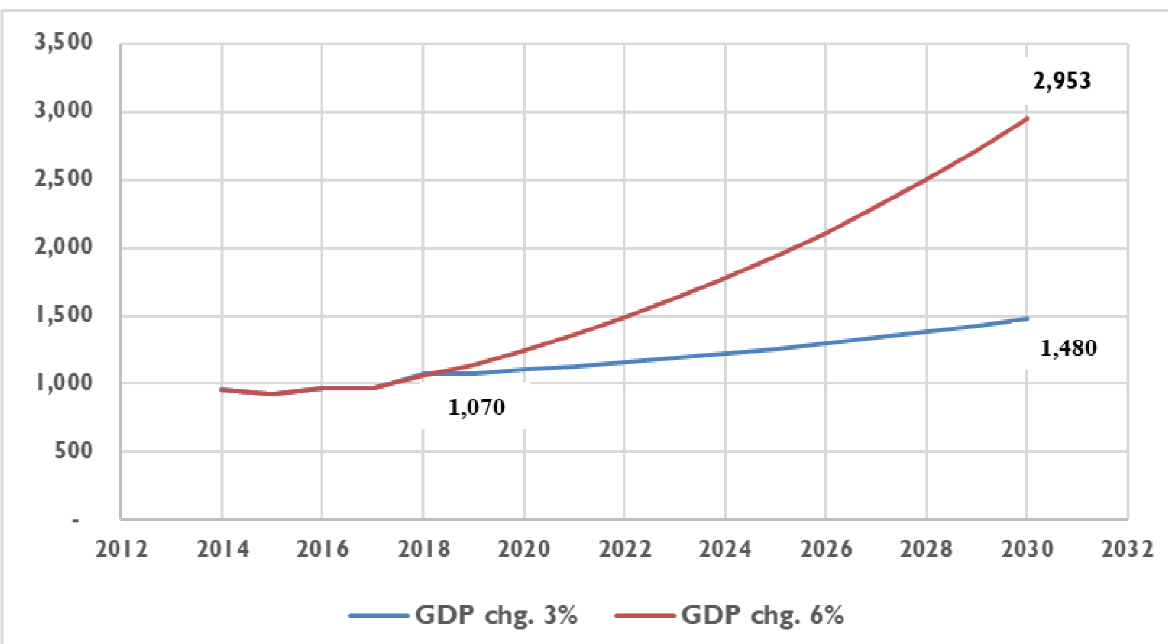
Exhibit 126 Natural Gas Demand Corresponding to Scenario B of GDP Growth.

Year	Population, million	Natural Gas Demand at 6% GDP annual Growth, million cubic meters a year				
		Private	Other	Power	Public	Total
2014	3.56	277	242	397	45	961
2015	3.56	272	215	398	43	928
2016	3.55	285	231	404	45	965
2017	3.55	303	233	384	45	965
2018	3.55	346	267	405	50	1,068

Year	Population, million	Natural Gas Demand at 6% GDP annual Growth, million cubic meters a year				
		Private	Other	Power	Public	Total
2019	3.55	387	297	399	53	1,136
2020	3.54	444	341	400	58	1,243
2021	3.54	507	390	400	63	1,359
2022	3.54	574	443	400	69	1,486
2023	3.54	647	501	401	75	1,624
2024	3.54	725	564	401	82	1,773
2025	3.53	810	633	402	90	1,934
2026	3.53	901	708	402	98	2,109
2027	3.53	999	789	403	107	2,297
2028	3.53	1,103	877	403	116	2,500
2029	3.52	1,216	972	404	126	2,718
2030	3.52	1,337	1,075	404	137	2,953

Graphic representation of the natural gas demand forecast scenarios is shown in Exhibit 127.

Exhibit 127 Natural Gas Demand Forecast, MCM/yr



5.6 CURRENT GAS AVALABILITY

Sources of gas supply to Moldova are limited in direction as well as in origin. As discussed in the previous sections, presently there are only two sources of natural gas supply, one via Ukraine and one via Romania (under construction).

5.6.1 GAS SUPPLY REQUIREMENTS FOR THE MOLDOVA COGENERATION PROJECT

The existing CHP sites in Chisinau and Balti are considered as likely candidates for the new generating capacities. Maximum available deliveries of the natural gas at the candidate sites and delivery pressure are presented in Exhibit 128.

Exhibit 128 Natural gas availability at the existing CHP sites

Site	Maximum available natural gas capacity, m^3/h	Site Delivery Pressure, Barg	Notes
CET-1	41,666	3	World Bank report [39]
CET-2	150,000 300,000	3 6	World Bank report
CET Nord	100,000	12	Minutes of Meeting [40]

Capacities of the natural gas network exit points/ pressure reducing stations (GRS) in the vicinity of Chisinau and Balti are presented in Exhibit 129.

Exhibit 129 Natural gas network capacity at Balti and Chisinau areas in 2017

Name of GRS	**Capacity, Nm^3/day**
SP Chișinău 1 Linia Oraș	2,400,000
SP Chișinău 1 Linia CET	2,400,000
SP Chișinău 2 Linia Mereni	2,400,000
SP Chișinău 2 Linia Oraș	2,400,000
SP Bălți Linia Oraș	528,000
SP Bălți Linia CET	672,000
SP Rîscani	147,000
SP Glodeni	646,000

Natural gas consumption by a 450 MW net / 530 Gcal/h GTCC CHP is estimated at approximately 125,000 m^3/h. Based on the available natural gas capacity data in Exhibit 128, the CET-2 site has sufficient natural gas infrastructure to support the fuel demand of a 450 MW net / 530 Gcal/h GTCC CHP.

Natural gas consumption by a 150 MW net GTCC is estimated at approximately 30,000 m^3/h. Both CET-1 and CET Nord have sufficient natural gas infrastructure to support operation of a 150 MW net GTCC.

5.6.2 SEASONAL GAS PRESSURE (HI & LOW)

Seasonal data for natural gas pressure in transmission pipelines has not been reported by Moldovagaz. There is data available about seasonal gas pressure fluctuation at CET-1 and CET-2 plants in Chisinau. However, this data is taken downstream of the pressure reducing stations at CET-1 and CET-2, and thus it could not be used as representative for the transmission and distribution network seasonal pressure fluctuations. Furthermore, Tokuz-Kainary-Mereny pipeline in Southern Moldova (Exhibit 115) with total length of 62.74 km was completed in 2007. This pipeline ensures reliably of maintaining constant pressure in the Chisinau area during the heating season period of maximum gas consumption.

5.6.3 FORECAST OF GAS AVAILABILITY

Following the completion of the ongoing infrastructure project in Turkey, Greece, Bulgaria and Romania the sources of supply of natural gas to Moldova are expected to become diversified.

There is a potential possibility for LNG to be supplied to Moldova from the LNG terminal in Greece. LNG supply could become viable once the required pipeline interconnectors are in place, especially with the Alexandroupolis LNG project.

Development of new pipeline interconnectors could open Caspian and Mediterranean, and even Algerian natural gas markets to Moldova. Reversing the existing Trans Balkan pipeline flow could provide for the possibility of Russian gas supply via Turkey.

Moldova could co-finance development of natural gas storages in Ukraine and Romania to secure reliability of the country's gas supply, since natural gas storages are not available in Moldova.

5.6.4 GAS RESERVES AND PRODUCTION IN COUNTRIES NEIGHBORING MOLDOVA

Additional information regarding gas production, reserves and markets in Moldova's neighboring countries Ukraine and Romania is presented in Appendix D.

5.7 FUTURE DEVELOPMENTS

Present and possible future natural gas supply routes to Moldova are presented in Exhibit 130, and take into account present saturation, forthcoming and developing alternates of natural gas supply on the Balkans. The developed scenarios consider currently available information and reflect decisions and actions taken by Moldova and the neighboring countries to overcome possible effect of natural gas supply interruption thru Ukraine. The scenarios consider planned and possible pipeline interconnections.

The legend of the gas supply routes in Exhibit 130 is presented below.

Supply Route	Color on the map
The existing supply routes ACB, ATI, RI, SDKR in North-South direction to Moldova as well as South – North to Moldova, Iasi – Ungheni	Grey
The existing reversed supply routes Reversed ACB, and Reversed Trans Balkan in direction to Moldova South – North	Marine Blue
Existing sample segment of Romanian network that is currently suppling natural gas to Iasi – Ungheni.	Light Grey
BRUA pipeline from Constanta, Romania to Csanadpalota, Hungary.	Light Green
A segment of Turkey Stream and its branch thru Bulgaria and Serbia	Dark Red
All the pipelines in SGC, as well as the Poseidon, Eastemed, IGB, IRB and LNG terminals	Dark Orange

Exhibit 130 Possible supply sources and routes, using ENTSOG system development map 2017 / 2018

5.8 FINDINGS RELATED TO NATURAL GAS SUPPLY

The natural gas infrastructure at the existing CET-1, and CET-2 and CET Nord CHP sites has sufficient capacity to support new power generation capacities considered in this study.

A summary of high-level qualitative risk assessment of the existing natural gas transmission infrastructure, market access and implementation of the new supply and transmission contracts is presented in Exhibit 131.

Exhibit 131 Pros and Cons of current and future natural gas supply scenarios

Supply source	Supply route	Pros / Risk Protection	Cons / Risk Areas
Moldova is procuring natural gas from Russia. No changes to current situation	Using same sources of supply via ACB, ATI, RI, SDKR.	No changes required in transmission network Established relations with natural gas supplier Natural gas quality and pressure remain stable/unchanged Long term contact for supply potentially through 2034.	The current transmission contract between Russia and Ukraine expired in 2019. On December 20, 2019, Ukraine and Russia reached a final agreement on principle positions on the transit of Russian gas through the territory of Ukraine through the end of 2024, with option to extend it through 2034 [41]. Even if the contract is extended through the end of 2034, it does not provide fuel supply certainty for a power plant commissioned in 2030 with a design life of approximately 25 years.
Moldova is procuring natural gas from Romania No changes to current situation	Iasi-Ungheni.	No changes required in transmission network Established relations with natural gas supplier Natural gas quality and pressure remain stable/unchanged Long term contact for supply	Romania still imports some natural gas. There is a risk in case of crises for Moldova
Supply from Russia via Ukraine is interrupted. Moldova is purchasing natural gas via Slovakia and Ukraine.	Reversed ACB.	Access to EU natural gas market New agreement for supply and transmission is required	Changes are required in the transmission network. Natural gas quality and pressure remain are unknown
Moldova is procuring natural gas from Ukraine reserves Supply from Russia via Ukraine is interrupted.	Supply via ACB, RI, ATI, SDRK,	Supply could be used as back-up supply in extraordinary situations.	Changes are required in the transmission network Natural gas quantities available are insufficient, for permanent supply meaning temporary/interruptible supply.
Moldova is procuring gas from Romania Supply from Russia via Ukraine is interrupted.	Reversed Trans Balkan ATI, RI, SDKR are reversed	Established relations with natural gas supplier Natural gas quality and pressure remain stable/unchanged Long term contact for supply	Changes are required in the transmission network

Supply source	Supply route	Pros / Risk Protection	Cons / Risk Areas
Moldova is procuring gas from Romania	BRUA, existing Romanian transmission network, Iasi-Ungheni-Chisinau	No changes required in transmission network Established relations with natural gas supplier Natural gas quality and pressure remain stable/unchanged Long term contact for supply	Romania still imports some natural gas. There is a risk in case of crises for Moldova
Moldova is procuring gas from Romania Supply from Russia via Ukraine is interrupted.	BRUA, Reversed Trans Balkan. ATI, RI, SDKR are reversed	Established relations with natural gas supplier Natural gas quality and pressure remain stable/unchanged Long term contact for supply	Changes are required in the transmission network
Moldova is procuring gas from Hungary	BRUA, existing Romanian transmission network, Iasi-Ungheni-Chisinau	No changes required in transmission network Access to competitive EU natural gas market	New supply route Data for available quantiles for procurements are unavailable Transmission and supply contracts to be further established
Moldova is procuring gas from Hungary Supply from Russia via Ukraine is interrupted.	BRUA, Reversed Trans Balkan. ATI, RI, SDKR are reversed	Access to competitive EU natural gas market	Changes are required in the transmission network New supply route Data for available quantiles for procurements are unavailable
Moldova is procuring gas from Turkstream Supply from Russia via Ukraine is interrupted.	Reversed Trans Balkan ATI, RI, SDKR are reversed	Natural gas quality remains stable/unchanged	Changes are required in the transmission network Transmission and supply contracts to be further established
Moldova is procuring gas from TANAP / TAP / POSEIDON / EAST MED	TANAP / TAP / POSEIDON / EAST MED, IGB, Bulgarian transmission network, Reversed Trans Balkan	Various sources of supply	Changes are required in the transmission network Transmission and supply contracts to be further established
Moldova is procuring gas from TANAP / TAP / POSEIDON / EAST MED	TANAP / TAP / POSEIDON / EAST MED, IGB, Bulgarian transmission network, IBR, Romanian transmission network, Iasi-Ungheni-Chisinau	No changes required in transmission network Various sources of supply	Transmission and supply contracts to be further established

Supply source	Supply route	Pros / Risk Protection	Cons / Risk Areas
Moldova is procuring LNG via Alexandroupolis LNG terminal or Revithoussa LNG Terminal	Greek transmission network, IGB, Bulgarian transmission network, Reversed Trans Balkan	Various sources of supply	Changes are required in the transmission network Transmission and supply contracts to be further established

Note: Criteria for capacity availability in SGC, BRUA, Turk Stream are intentionally omitted since this a free market matter executed under tendering procedures.

5.9 TECHNICAL WATER FOR NEW GENERATING CAPACITIES

5.9.1 INTRODUCTION

Fossil power plants consume significant amounts of water for their operation. Thus, availability of water in sufficient quantities is one of the critical factors in developing new power generating capacities. This section presents an analysis of potential water sources and uses for the purpose of developing new thermoelectric generating capacities in Moldova.

5.9.2 WATER REGULATIONS

Potential sources of fresh water makeup for power plants are rivers, lakes, and wells, or municipal sources. Moldova's surface waters resources are relatively limited [42]. The proper use and protection of water resources and the search for the new sources of water is a matter of national security importance for the relatively densely populated Moldova. Use and consumption of water in Moldova is regulated as described below.

Under the Moldovan law, water defined as "General Use Water" does not require environmental permits if utilized for the following purposes:

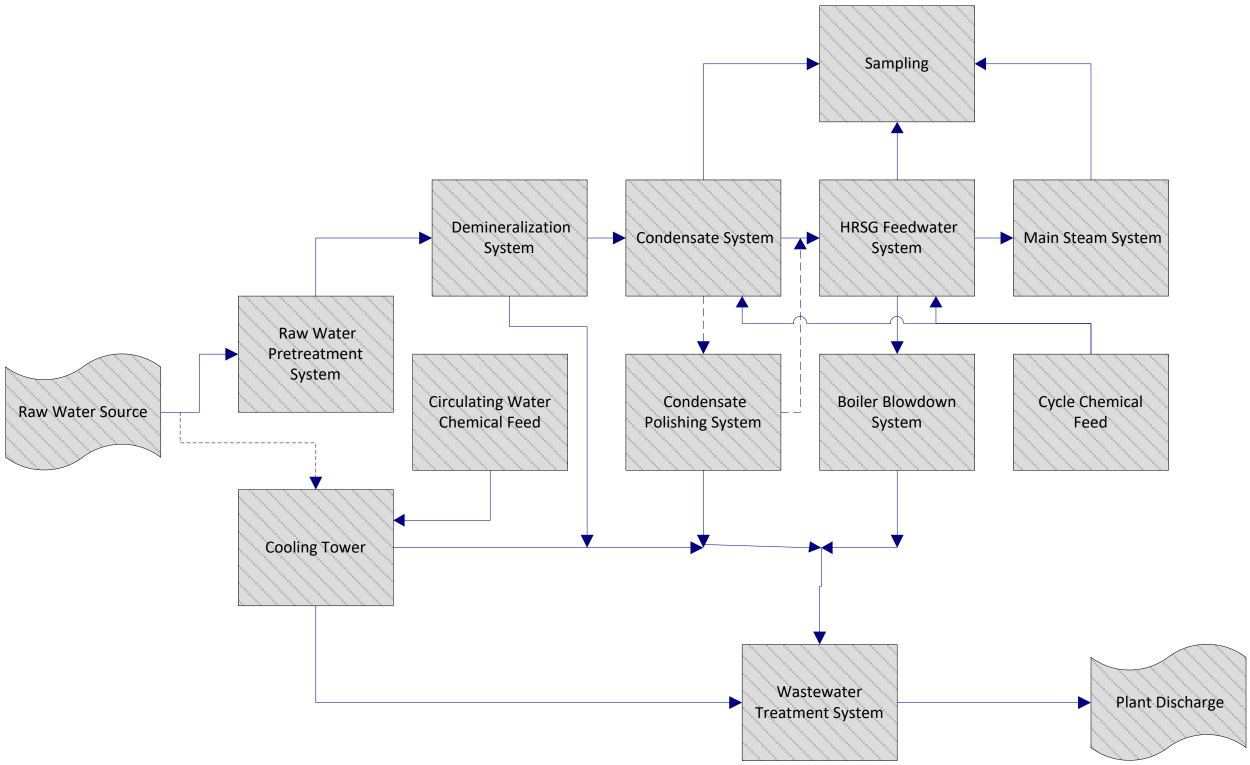
- water consumption for drinking purposes and for other household needs;
- water for cattle without the use of stationary structures;
- irrigation for homesteads;
- recreational use;
- water use for firefighting or other emergencies

There is a "Special water use" provision under the Moldova Law. The use of water for the purposes that are not included in the definitions described in the "General Use Water" provisions is considered to be a "Special Water Use" that requires a permit. The collection and use of water from surface and underground sources for technical and industrial purposes, such as a GTCC or CHP power plant, as well as a wastewater discharge falls under the requirements of "Special Water" use.

5.9.3 POWER PLANT USES FOR WATER

Typical power plant uses of water and water treatment systems are presented Exhibit 132.

Exhibit 132 Typical Power Plant Water Systems



Some of the relatively minor uses of water, such as potable water, sanitary water, etc. are not shown in the Exhibit 132. Major power plant uses of water and types of plant water are presented in Exhibit 133.

Exhibit 133 Types and Uses of Power plant water

Uses of Water	Types of Plant Water
Boiler/HRSG Makeup (Blowdown)	Demineralized
Condensate, Feedwater, Steam Cycle	Demineralized
Startup	Demineralized
Reverse Osmosis (RO),	Filtered /Service
Condensate Polisher	Condensate
Firefighting	Filtered /Service
Cooling Tower Makeup	Filtered / Service
Drinking, showers, sanitary	Potable

Power plant water system also includes storages of different types of water. Typical major water tanks at a power plant are presented in Exhibit 134.

Exhibit 134 Major Water tanks at a Power plant

Major Water tanks	Sizing Criteria
Raw water tank	Sized to ensure uninterrupted power plant operation in case of a failure of a raw water supply source (river intake, municipal source, etc.). Sizing is dictated by reliability of a water source, or local design codes
Service water tank	Sized to accommodate all the plant service water uses and insure uninterrupted power plant operation in case of a failure of the plant raw water pre-treatment system
Fire water tank	Sized based on the local fire code regulations. Sometimes combined with a service water tank
Demineralized water tank	Sized to accommodate all the plant demineralized water uses and ensure uninterrupted power plant operation in case of maintenance, or a failure of a demineralized water system
Condensate tank	Sized to accommodate plant steam system operating modes

A water balance analysis is performed during a power plant design considering all the major water consumers and processes. Raw water makeup is the water removed from a river, ground well or diverted from a municipal source for use in the plant. The total water demand for each subsystem is determined and internal recycle water available from various sources like boiler feedwater, blowdown and demineralization blowdown is applied to offset the water demand. The difference between water demand and recycled water is raw water withdrawal. Raw water consumption is accounted for as the portion of the raw water withdrawn that is evaporated, or otherwise not returned to the water source from which it was withdrawn. A discharge of treated effluent by a power plant into natural and man-made water bodies/ reservoirs is governed by the local environmental regulations. Discharges into the local municipal sewer systems are determined by the available capacity of the system.

Cooling tower makeup is the largest consumer of raw water for the power plants equipped with an evaporative cooling tower. As illustrated in Exhibit 132, to reduce water consumption, the modern power plants employ such a design that all process blowdown streams are typically treated and recycled to the cooling tower.

For example, raw water withdrawal on a per MW net power generation basis at ISO conditions [43] for a modern 600 MW-class GTCC equipped with evaporative cooling tower is approximately 1 m^3/h, which includes approximately 0.8 m^3/h of water consumption and 0.2 m^3/h of water discharges. Evaporative cooling tower water consumption accounts for more than 95% of the total plant water consumption and almost 100% of the total plant water discharges. For comparison, raw water withdrawal on per a MW net of power generation basis at ISO conditions for a modern 600 MW class GTCC equipped with Air Cooled Condenser (ACC) is approximately 0.01 m^3/h (steam cycle makeup), and water discharges are approximately 0.005 m^3/h.

Selection of a cooling system type determines the overall raw water withdrawal by a power plant. Power plant cooling refers to rejection to the environment of heat released in condenser of a steam turbine by condensing exhaust steam. Other cooling requirements, commonly referred to collectively as "auxiliary cooling", include, such items as lube oil cooling, generator cooling and transformer cooling. The auxiliary cooling load is small compared to the main condenser cooling load.

Power plant cooling systems are commonly one of four types. These are:

- Once-through cooling,
- Closed-cycle wet cooling,
- Dry cooling, and
- Hybrid (wet/dry) cooling.

In once-through systems, cooling water is withdrawn from a natural waterbody, passed through the tubes of a steam condenser and heated water returned to the waterbody. Due to limited surface water resources in Moldova [42], once-through cooling system option is not considered for the new power generation capacities. The choice among the remaining cooling systems involves a number of tradeoffs including system capital cost, operation and maintenance (O&M) requirements, effects on plant efficiency and capacity, water requirements (both withdrawal and consumption) and a variety of environmental issues including wastewater discharge, drift, noise, aesthetics and visible atmospheric plumes. While for the example above, utilization of an ACC could result in reduction of the GTCC power output by approximately 2% and efficiency reduction of about 2.5%, selection of a cooling system for a GTCC plant (evaporative or ACC) is primarily dictated by availability of raw water and environmental regulations in case of the natural fresh water sources, and available capacity in case of the local municipal water sources.

A thermodynamic cycle employed by a power plant also has a significant impact on the water demand. Only about a third of the total plant power is generated by the Rankine (steam) cycle portion of a GTCC plant. Thus, the cooling load of a GTCC plant is about one third of the cooling load of a Rankine cycle plant, such as CET-2. However, during the heating season extraction type CHP steam turbines (such as the CET-2 turbines) have significantly lower condenser cooling duty as compared to operation in condensing mode, as a large portion of the latent heat released by the condensing steam is utilized to heat the district heating system water. As a result, power plants utilizing a CHP cycle have lower water consumption and waste water discharges as compared to the power plants generating only electric power.

In summary, a GTCC plant equipped with a CHP steam extraction turbine should have the lowest demand for raw water. A choice of cooling system and thermodynamic cycle for the new generating capacities can affect site selection flexibility and overall plant cost by, for example, allowing the location of a plant close to fuel resources which may be in areas of very limited water supply.

5.9.4 EXPECTED WATER SOURCES AND MAKEUP WATER REQUIREMENTS

From the stand point of raw water availability, the existing CHP sites in Moldova present the best candidate sites for the new generating capacities. These sites already have permitted municipal sources for the raw water supply and waste water discharge. For the purposes of this assessment, it is assumed that the new generating units that are to be located on the existing sites (brownfield sites) should be designed with raw water makeup and waste water discharge requirements that will not exceed the currently available raw water and waste water capacities of the municipal sources and permits at these sites. The new generating capacities on the brownfield sites could be designed with either evaporative cooling system or ACC, as long as the raw water makeup and the waste water discharge flow rates are within the existing site limits. Basic parameters of the cooling systems at the existing CHP sites are presented in Exhibit 135.

Exhibit 135 Parameters of Cooling Systems at the Existing CHP sites

Parameter	Units	Value	Notes
Cooling available at CET-1			
Two cooling ponds, ea	m^3	1000	Steam Turbine aux cooling loads. System is reported as unreliable
Cooling available at CET-2			
Design cooling system capacity	MWth	156.6	Source [44]
Cooling towers makeup requirement	m^3/h	250	Source [45]
Maximum Available makeup water	m^3/h	800	Potable water is sourced from the SA APA-Canal company.
Average waste water discharge	m^3/h	80	Waste water is discharged to the SA APA-Canal company sewage system
Cooling Available at CET Nord			
Annual water consumption	m^3	176,731	Makeup water comes from the city water system. In addition, there are 5 emergency artesian water wells [46]. Consumption is reported for 2018 [47]
Annual waste water discharged	m^3	30,199	Wastewater discharges are disposed to the city seaware system Consumption is reported for 2018

5.9.5 PLANT WATER BALANCE

Based on the preliminary thermodynamic and water balance analyses of a new 400 MW CHP plant that utilizes GTCC cycle, equipped with evaporative cooling tower and providing heat to the Chisinau district heating system, its cooling system capacity is estimated at approximately 100 MWth, while supporting a district heating load of 400 Gcal/h. Cooling system duty in condensing mode is estimated at approximately 130MWt. The amount of raw water necessary to compensate for the evaporative cooling tower and steam-water cycle losses is estimated at approximately 300,000 m^3/yr for a plant capacity factor of 85%. The waste water discharges to the sewer system are estimated at approximately 80,000 m^3/yr.

A cooling system duty for a new electric power only 160 MW GTCC unit is estimated at approximately 50 MWth.

5.9.6 FINDINGS RELATED TO WATER USES

The estimated raw water demand and waste water discharge requirements for the new generating capacities at CET-2 site can be satisfied by the existing SA APA Canal municipal water and sewer systems. Evaporative cooling system could be considered for a new power only GTCC unit if located at the CET Nord site.

Considering relatively limited water resources in Moldova, it is recommended that any new power generating capacities that are to be located on a new "greenfield" site should be designed with an ACC type cooling system to minimize raw water consumption and waste water discharge requirements.

The approach of utilizing the existing water sources at the brownfield sites and air cooling at the greenfield sites should streamline the permitting process for the new power units (utilize the existing "Special Water Use" permit) and reduce/eliminate additional capital investments attributed to the raw water and waste water utilities.

6 TASK 4: LAND AND STRUCTURAL ISSUES

6.1 EVALUATION CRITERIA

This section provides a high-level assessment and ranking of the possible suitable locations for the new generating capacities in Moldova. This assessment is primarily focusing on proximity and availability of the required utilities interconnections, such as high voltage electric substation, district heating system, natural gas connection, makeup water and waste water systems. It also takes into account any potentially reusable existing structures, facilities and systems and available space on the existing sites.

The sites are evaluated and ranked utilizing qualitative scoring system based on the following criteria:

- Site characteristics: land availability, site location relative to sensitive noise receivers, environmental, topography, and geology, groundwater, seismic, that may result in additional site preparation requirements.
- Infrastructure: site access (road and rail), proximity to water supply and effluents discharge systems, natural gas piping, and HV lines/substation.
- Engineering: DH network, existing facilities on site suitable for re-use or requiring demolition, water treatment requirement, etc.

6.1.1 SITE CHARACTERISTICS

Site selection indicators [48] include available footprint for a candidate plant, site conditions, topography, geological and hydrological characteristics. Site conditions can significantly affect the construction costs of the project. A summary of site characteristic and their potential impacts on a power plant design is presented in Exhibit 136

Exhibit 136 Site Characteristics and their Impacts on Plant Design

Site Characteristics	Potential Impacts
Location	Undesirable site locations for a thermal power plant include being in the immediate vicinity to airports, warehouses with explosives, nature reserves, national parks, historical and cultural monuments, or sensitive noise receivers such a residential areas, schools or hospitals etc.
Environmental	It is undesirable to locate thermal power plant sites within residential areas and recreational areas, or in proximity to them or sensitive receivers such as schools and hospitals, as it may trigger more stringent environmental requirements related to air emissions and noise and invoke additional architectural and fire protection regulations. Areas with the existing severe environmental issues where background pollution levels already approaching or exceeding acceptable standards should be avoided. Sites with the existing environmental problems may require additional costs related to more stringent air pollution control equipment, soil remediation, asbestos removal, etc.

Site Characteristics	Potential Impacts
Topography	A site with level naturally gently sloping topography that provides rainfall runoff is preferred for power plant construction. Nearby mountain terrain may have a significant impact on plant flue gas dispersion characteristic. Sites with mountain terrain are likely to require additional site preparation work, which will have negative impact on capital costs.
Geology	Site geotechnical conditions affect foundation design for the plant buildings and structures. Special attention is given to identifying sites susceptible to physical and geological processes, such as avalanches, landslides, sink holes, etc.
Groundwater	Site located in proximity to an open water body is likely to have high water table and may be susceptible to flooding. This could result in increased construction costs to assure proper drainage of the site, and waterproofing protection of buildings, basements and underground engineering networks to prevent flooding.
Seismic conditions	Design of power plant located in the area with high seismic activity requires special provisions to assure its survivability and safety during a seismic event. Such design provisions may have significant impact on power plant capital costs.

6.1.2 INFRASTRUCTURE CRITERIA

The Infrastructure criteria include: access roads, railways and waterways; fuel supply sources; availability of a makeup water source and a receiver of waste effluents; and environmental considerations. Site infrastructure criteria for selecting the location of a power plant and the criteria potential impacts on a plant design are presented in Exhibit 137.

Exhibit 137 Site Infrastructure Criteria and Impacts

Infrastructure Criteria	Potential Impacts
Access	It is desirable for a power plant location to be accessible by the existing roads, railways and/or waterways. It is especially important that the site access be suitable for heavy/oversized haul cargo deliveries, such as a gas turbine, steam turbine, sections of HRSG, generator step-up transformers, etc. A transportation logistics study is typically conducted to develop logistics for various heavy haul oversized cargoes. Such a study would survey potential routes considering conditions of access roads/railways and engineering structures (bridges, crossings, tunnels, etc.), in-route regulatory requirements and transportations and route modification costs.

Infrastructure Criteria	Potential Impacts
Fuel supply	Site selection for a natural gas fired power plants should take into account the proximity to the existing natural gas distribution network. The desired natural gas supply pressure to the gas turbine power plant sites is at least 45 Barg. Sites with lower available gas pressure will require fuel gas compressors, which would add to the plant capital and operating costs. .
Water Supply/Effluent Disposal	Raw and potable water supply sources and access to a sewer system are very important factors for a potential site selection. Sites with no access to the sources that could provide sufficient makeup water supply and waste water disposal have to be designed with air cooling system, such as Air-Cooled Condenser (ACC), a notable cost adder to the plant capital costs and potential detrimental effect on plant performance.

6.1.3 ENGINEERING CRITERIA

Engineering site evaluation criteria primarily deal with the systems, interconnections, structures, etc. that may exist at a site and can be repurposed and reused for a new power generating plant. Site engineering criteria and their impacts on plant design are presented in Exhibit 138.

Exhibit 138 Site Engineering Criteria and Impacts

Engineering Criteria	Potential Impacts
Electric power network	It is advantageous for a power plant location to be in the proximity of the existing high voltage transmission network infrastructure, with voltage and capacity suitable for evacuation of the electric power generated by the plant. Construction of new high voltage transmission lines could add substantially to the project capital costs. Proximity to the large power load centers (such as Chisinau) is typically preferred, although it depends upon the existing power grid structure.
District Heating	A site for a CHP plant has to be in the immediate proximity to a district heating network. The cost of interconnecting a remotely located CHP could be significant and the efficiency and cost of operation of such a CHP could be negatively affected by additional district heating pumping loads and maintenance costs. Considerations are given to the annual heat load profile of a district heating system when selecting configuration and output of a new CHP to maximize its annual operation in a cogenerating mode while fully utilizing the new unit capacity.

Engineering Criteria	Potential Impacts
Existing Facilities	Utilization of any site that already has the existing interconnections to HV power, fuel gas, district heating, makeup water, and sewer discharge that could be repurposed and reused for a new power plant could bring notable capital cost savings. It would also reduce the project development schedule. Additional savings may include reuse of the existing buildings, storage tanks, auxiliary boilers, etc.

6.1.4 RELATIVE COSTS

Quantitative assessment of the capital expenditures (CAPEX) associated with a site development requires already developed design of a new plant, at least on a conceptual level. Plant designs for the new generating capacities in Moldova have not been developed at this stage of the project. However, potential cost implications of the site attributes related to the site selection criteria have been considered qualitatively based on engineering judgement and experience of the Worley project team.

6.2 CANDIDATE SITES

Candidate sites are presented in Exhibit 139 and have been selected based on discussions with the project stakeholders in Moldova that included Termoelectrica, Moldelectrica, Ministry of Economy and Infrastructure, and CET Nord. CT Vest and CT Sud sites have been included based on recommendations of the recently completed World Bank study [2].

Exhibit 139 Candidate Sites

Site	Site Status	Current Configuration	Configurations for Consideration	Location	Coordinates
CET-1	Brownfield	CHP	Power Only	Chisinau	47.02555, 28.86737
CET-2	Brownfield	CHP	CHP	Chisinau	47.02986, 28.89399
CT-VEST	Brownfield	Heat Only	CHP (note 2)	Chisinau	47.04235, 28.8071
CT-SUD	Brownfield	Heat Only	CHP (note 2)	Chisinau	46.99241, 28.82325
CT East	Brownfield	Power Only [Not currently in operation]	Power Only	Chisinau	46.97171, 28.91604
CET Nord	Brownfield	CHP	Power Only	Balti	47.74934, 27.89398

Notes:

1. Brownfield site status designates a site of the existing power plant.
2. CT-VEST and CT-SUD can operate all year round as a CHP with a total installed heat capacity of approximately 50 Gcal/h.

6.2.1 ATTRIBUTES OF THE CANDIDATE SITES

Major attributes of the candidate sites are presented in the following exhibits.

Exhibit 140 Makeup Water and Effluent Discharge

SITES	Pressure, bar	Water Supplier / Effluent Receiver	Distance, km
CET-1	>3	SA APA CANAL CHISINAU	1-3
CET-2	>3	SA APA CANAL CHISINAU	1-3
CT Vest	>3	SA APA CANAL CHISINAU	1-3
CT Sud	>5	SA APA CANAL CHISINAU	1-3
CT East	>4	SA APA CANAL CHISINAU	1-3
CET Nord	>3	SA APA CANAL BALTI	8

Notes:

1. For CET-2 available maximum technical water makeup from SA APA CANAL is 800 m^3/h
2. For CET-2 average water blowdown to SA APA CANAL city sewer system is 80m^3/h
3. For CET Nord 2018 annual makeup water consumption 176,731 m^3, and annual water discharge 30,199 m^3

Exhibit 141 Electric HV Power Interconnections

Site	Voltage, kV	Switch Yard	Substation	Distance, km	Comments
CET-1	2x110	SY EX	SS EX	1	
CET-2	3x110	SY EX	Straseni	25	distance to 330kV substation
CT-VEST	4x6	SY EX	SS EX	5	
CT-SUD	4x6	SY EX	SS EX	8	
CT East	2x110	SY EX	SS EX	3	
CET Nord	3x110	SY EX	Balti	15	distance to 330kV substation

Notes:

1. SY EX is the existing switchyard that would require minor modifications
2. SS EX is the existing Sub Station that would require minor modifications

Exhibit 142 Tie-in points status- natural gas supply

Site	Pressure, Barg	Connection	Comments
CET-1	3	ON SITE	Winter pressure on site is reported unreliable max available flow rate is 41,666 m3/h [2]
CET-2	3 6	ON SITE	Winter pressure on site is reported at 1 Barg max available flow rate is 150,00 m3/h at 3 Barg max available flow rate is 300,00 m3/h at 6 Barg [2]
CT-VEST	3	ON SITE	max available flow rate is 54,000 m3/h [2]
CT-SUD	5	ON SITE	max available flow rate is 41,100 m3/h [2]
CT East	4	ON SITE	
CET Nord	3	SPG BALTI	Design pressure is 12 Barg; max design flow rate is 100,000 m3/h

Notes:

1. All sites will require a fuel gas compressor for a new gas turbine-based power plant to elevate incoming pressure to at least 45 Barg.
2. For CET-2, an existing pipeline with 12 Barg design pressure is 3 km away, and an existing pipeline with 35 Barg pressure is 7 km away

6.3 SPACE CONSIDERATIONS

This section provides estimates of approximate space at the candidate sites that is available for the new power generating units. Also provided are several examples of power units layouts and their dimensional envelopes. These layouts are compared to the available space at the candidate sites.

6.3.1 AVAILABLE SPACE AT THE CANDIDATE SITES

Aerial views and maps of the candidate sites are shown in Exhibit 143, Exhibit 144, Exhibit 145, Exhibit 146, Exhibit 147, and Exhibit 148 for CET-1, CET-2, CET-VEST, CT-SUD, CT-East, CET-Nord BALTI respectively. The images have a yellow demarcation to show the approximate site boundaries. Some of the images also include a red demarcation of available area that could be utilized for the new power units. A scale comparison of various site outlines along with dimensions is presented in Exhibit 149.

Exhibit 143 Aerial View of CET-1

Source: [2], [49]

Exhibit 144 Aerial View of CET-2

Source: [49]

Exhibit 145 Aerial View of CT-VEST

Source: [2]

Exhibit 146 Map and Aerial view of CT-SUD

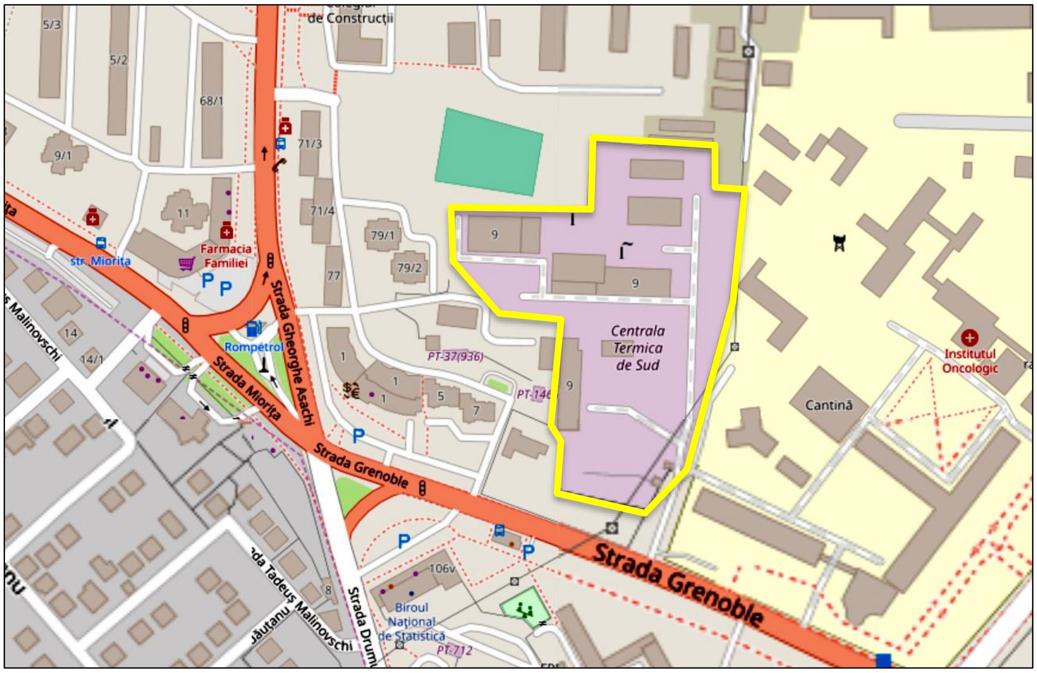
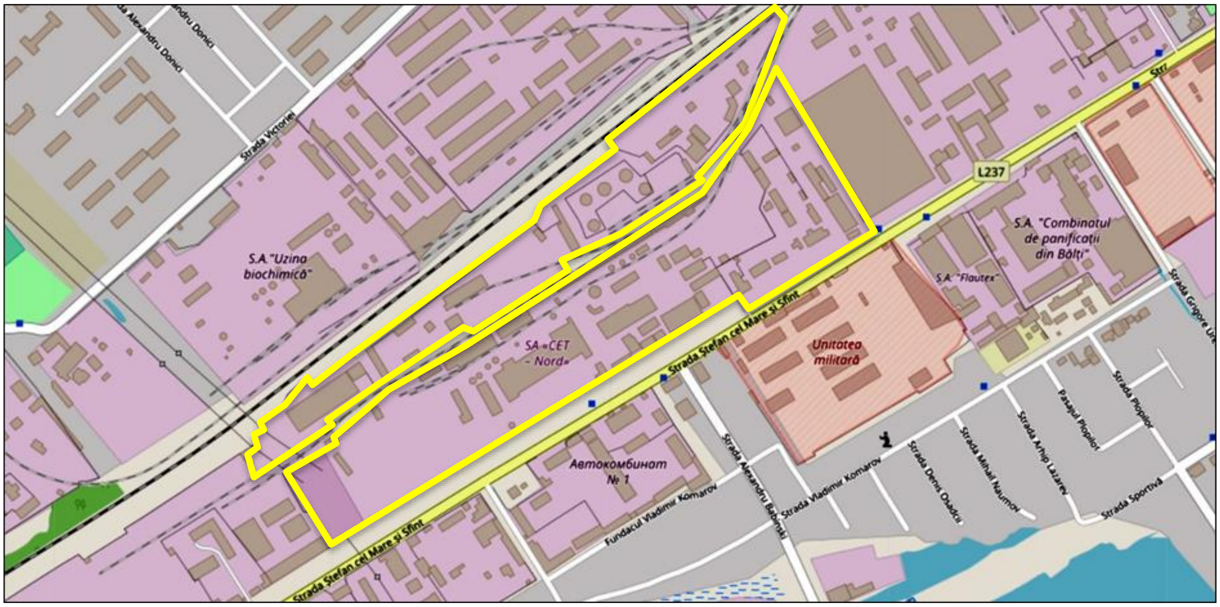
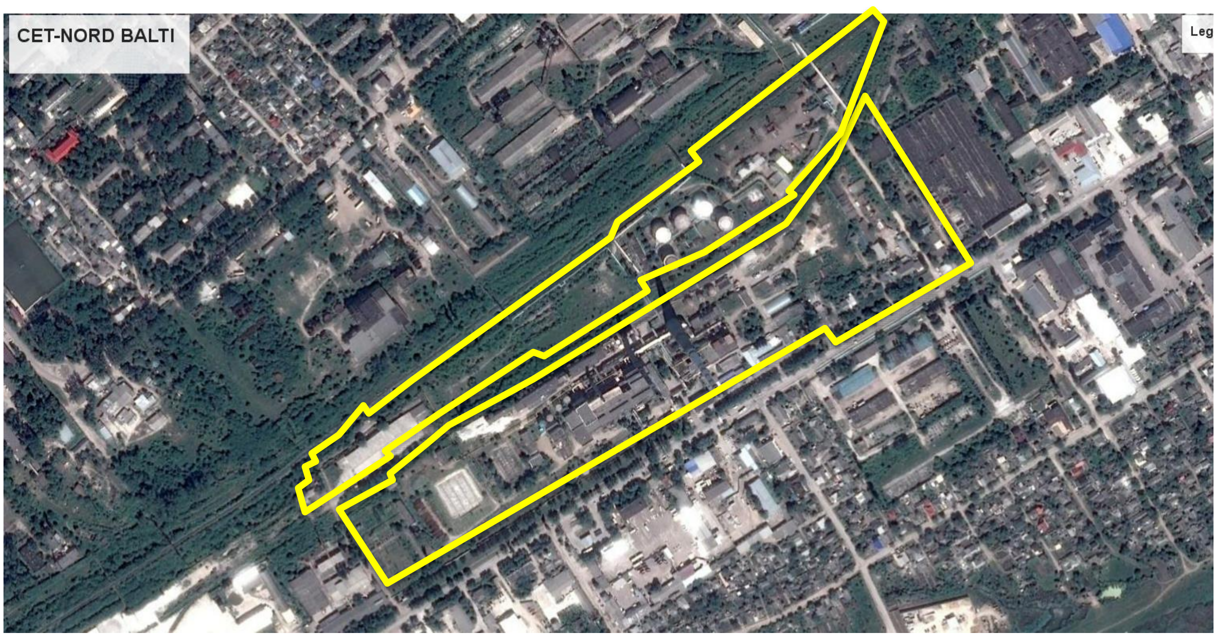


Exhibit 147 Aerial View of CT East

Source: [49]

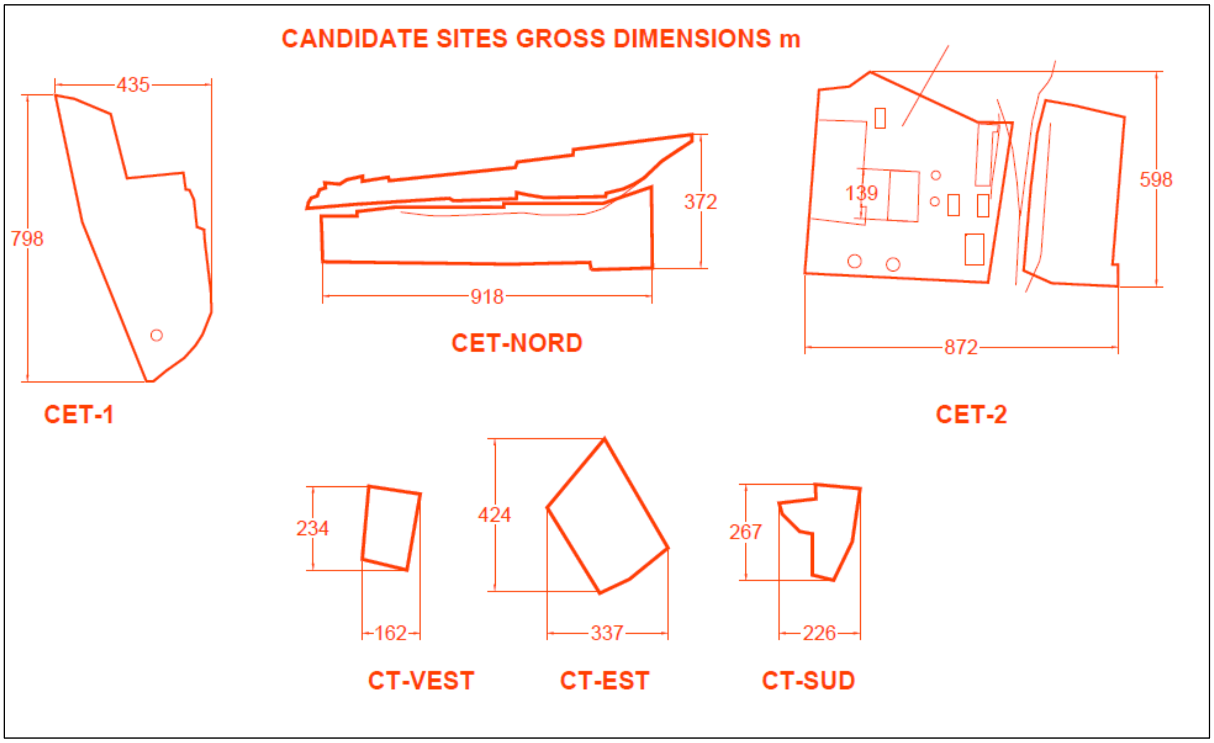
Exhibit 148 Map and Aerial view of CET-NORD BALTI





Approximate layouts and dimensional envelopes of the candidate sites have been derived from the available aerial images, maps and schematics and are presented in Exhibit 149.

Exhibit 149 Approximate Dimensions of the Sites



Estimates of the approximate total and available space at the candidate sites is presented in Exhibit 150.

Exhibit 150 Approximate Available Area at candidate Sites

Site	Total Area, hectares	Available area, hectares
CET-1	16.9	2.16
CET-2	29.4	7.31
CT-VEST	2.8	0.2
CT-SUD	3.3	Note 3
CT East	7.4	NR
CET Nord	30	2

Notes:

1. NR – Not reported. Although the available area was not reported, it is believed to be adequate for CHP and/or Heat only options being considered particularly since the plant is not currently in operation.
2. Layouts of the CT Vest and CT SUD sites will need to be redesigned to accommodate a new power plant.
3. At CT SUD the new generating equipment can be located in the existing steam boiler building, requiring removal of the existing steam boilers [2].

6.3.2 EXAMPLES OF GAS TURBINE UNITS LAYOUTS

Sample layouts and dimensional envelopes of power plants utilizing gas turbines are presented in Exhibit 151, Exhibit 152, and Exhibit 153.

Exhibit 151 EXAMPLE of 100-120 MW SIMPLE CYCLE GAS TURBINE LAYOUT

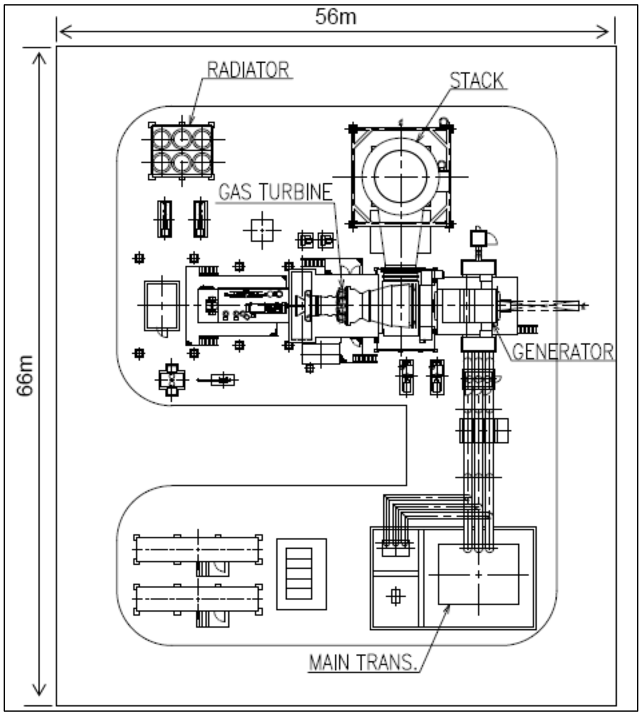


Exhibit 152 Example of 150-70 MW GTCC LAYOUT

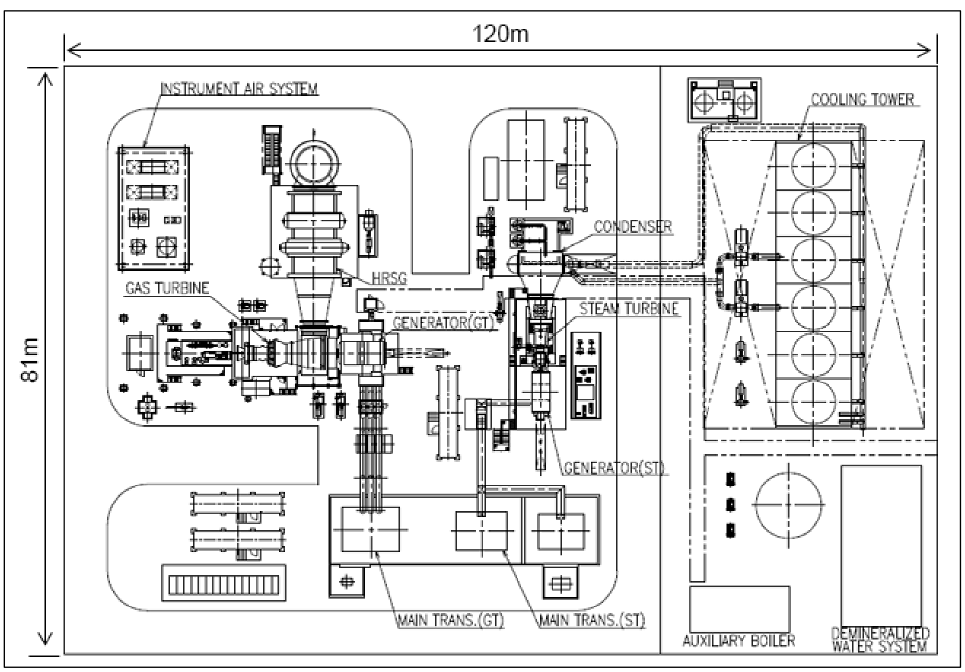
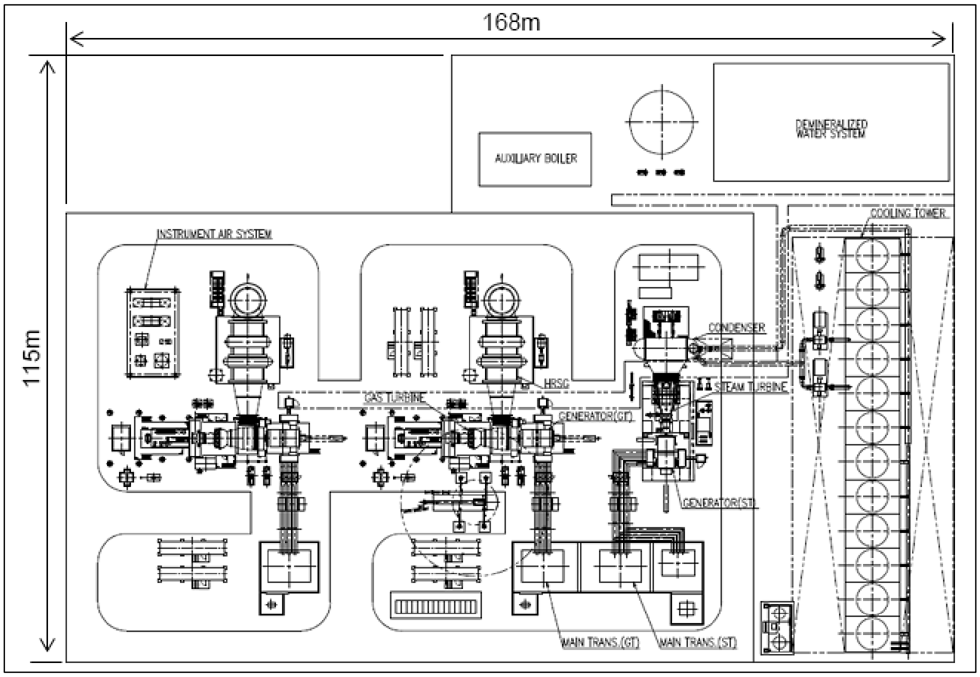


Exhibit 153 Example of 300-320 MW GTCC LAYOUT



Approximate area requirements for the above examples of the power plant layouts are summarized in Exhibit 154.

Exhibit 154 Approximate Area Requirements for Thermal Plants

Unit Type	Unit Capacity, MW	Length, m	Width, m	Area, m²	Area, hectare
GT SC	100-120	66	55	3,630	0.4
GTCC	150-170	120	81	9,720	1.0
GTCC	300-320	168	115	19,320	1.9
RICE	21-31	70	60	4,200	0.4

Note: Space requirements for the Reciprocating Internal Combustion Engine (RICE) plants is estimated based on Worley in-house information.

It can be seen, based on comparison of the available space at CET-1, CET-2, CT Vest, CT Sud, and CET Nord sites (Exhibit 150) with the approximate area requirements of the sample power plant configurations that these candidate sites should have sufficient space to facilitate addition of the new power units. Space sufficiency at the CT East site cannot be ascertained at this time, as its available space has not been reported.

6.4 CANDIDATE SITES EVALUATION AND SELECTION

Five sites in the area of Chisinau and one site in Balti were identified as having promise to be a host site for the new thermal electric generation capacities (Exhibit 139). All the sites are potentially suitable for a CHP configuration. However, CHP operation at the CET-1, CET Nord and CT East sites is judged as not economical. CET-1, CT East and CET Nord sites are considered for the new electric power only units.

Several evaluation attributes are selected to rank the candidate sites, and a qualitative analysis conducted. Each evaluation parameter received a weighting of 1 to 5, with 5 reflecting the greatest importance. Site specific scores were assigned for each of the evaluation areas with scores ranging from 1 to 10, with 10 being most favorable. The total site score was developed by summing the weighted scores for all of the evaluation parameters. Thus, a higher score reflects a better suitable site.

Each of the evaluation attributes is discussed below:

- CET-1, CET-2, and CET Nord sites were given identical score for available space.   CT Vest site was given somewhat lower score. CT Sud and CT East were given lower scores, as layouts of the CT Vest and CT SUD sites will need to be redesigned to accommodate a new power plant, and limited information is available about CT East.
- CET-1, CET-2, and CET Nord are located in what appear to be industrial zones of Chisinau and Balti. However, over the years residential housing has moved closer to the industrial zones. These sites given identical score for proximity to residential areas. There are no residential areas in the vicinity of CT East site, and it received the highest score in this category. CT Vest and CT Sud were given the lowest score as these sites are located fairly close to the residential areas.
- Topographical conditions have been assessed through site visits, the topographical maps, and photographs. All sites were given identical score in this category as judged to require the approximately the same earth moving work, and heights of stacks. All sites are also expected to have similar geological and seismic conditions.
- The environmental impact of the gas-fired power plant is expected to be minimal and relatively independent of the site location. All new plants are expected to be designed to meet the European Union environmental regulations.
- Access roads and railway scoring reflects the classification of the road providing access to the site boundary and reflects proximity of the rail to the proposed site. CET-2, CT East and CET Nord have been given a higher score as having rail road access on site.   However, the condition of the rail lines is not known.
- Water supply is a highly weighted parametric area in light of the large quantities of water that are required for cooling. All of the candidate sites have access to municipal water sources that can provide sufficient makeup water supply and effluent offtake and thus received an identical rating, except for CT East site, for which water supply information is not available.
- Natural gas fuel supply is another highly weighted parametric area as high reliability and large quantities fuel gas supply are required for a power plant operation. CT Vest and CT Sud sites received a higher score in this category as potential sites for reciprocating engine units only that require a low-pressure gas. All other sites received a lower score as potential candidate sites for gas turbine units that require fuel gas pressure of approximately 45 Barg. Currently all the sites receiving natural gas at 3 Barg. Gas turbine plants will require large gas booster compressors, which should add capital and operating costs. The adequacy of the natural gas flow is determined in Task 6, where the flowrate is shown to be adequate for all sites.
- CET-1, CET-2 and CET Nord sites were given identical scores for electric connections. These sites currently are connected to 110kV transmissions lines and potentially can be connected to 330kV network. CT Vest and CT Sud were awarded the lowest scores in this category as these

sites are connected to 6kV network and may potentially be required to be connected to a high voltage system, at additional capital expenditures. CT East was given a somewhat lower score due to the limited information.

- CET-2, CT Vest and CT Sud sites were given identical scores for proximity to the district heating network connections, as having the district heating connections on site. CET-1, CT East, and CET Nord sites are not scored in this category as they are envisioned to host a power only unit.
- Value of capacity utilization on site in meeting DH demand category evaluates sites on their potential of maximizing district heating revenues. CT Vest and CT Sud sites received the highest scores in this category as new units on both sites have an opportunity to operate all year around in efficient cogenerating mode. CET-2 site received a lower score, as a new unit on this site could only operate in cogenerating mode during the heating season. CET-1, CT East, and CET Nord sites are not scored in this category as they are envisioned to host a power only unit.
- All sites, except CT East and CT Sud sites were given an "existing facilities reuse score" of 5, or weighted score of 10. CT East site was given a lower score because of due to the limited information. CT Sud was given a lower score of 3, as at CT SUD new generating equipment can be located in the existing steam boiler building, requiring removal of the existing steam boilers.
- For "Extensive demolition requirement" category all sites received identical score, except for the CT East site due to the limited information.

The results of the evaluation are presented in Exhibit 155.

Exhibit 155 Qualitative Assessment for Site Selection

	Evaluation Parameters	Weight Factor	Weighted Score					
1	**Site Characteristics**	**1 to 5**	**CET-1**	**CET-2**	**CT Vest**	**CT East**	**CT Sud**	**CET Nord**
	Available footprint (plant, laydown)	3	18	18	15	9	9	18
	Proximity to residential area.	2	14	14	10	16	10	14
	Topography, Geology, Hydrology, Earthquakes	3	15	15	15	15	15	15
	Environmental Issues	5	25	25	25	25	25	25
2	**Infrastructure criteria**							
	Access Roads and railways	3	12	18	12	18	12	18
	Water access & availability	4	24	24	24	16	24	24
	NG Fuel supply sources	4	20	20	32	20	32	20
3	**Engineering criteria**							
	Distance to electrical interconnection.	5	20	20	10	15	10	20
	Distance acess to district heating network.	5	0	25	25	0	25	0
	Value of capacity utilization on site in meeting DH demand	5	0	40	50	0	50	0
	Existing facilities to re-use	2	10	10	10	4	6	10
	Extensive demolition requirement	2	6	6	6	4	6	6
	CUMULUTIVE WEIGHTED SCORE for CHP sites			**235**	**234**		**224**	
	FIINAL RANKING of CHP sites			**1**	**2**		**3**	
	CUMULUTIVE WEIGHTED SCORE for Power only sites		**164**			**142**		**170**
	FIINAL RANKING of Power only sites		**2**			**3**		**1**

6.5 RECOMMENDATIONS

Among the CHP sites none of the resulting scores would preclude any of the three sites from being considered in Task 6. As such all three CHP sites (CET-2, CT-Vest, and CT-Sud) will be considered in Task 6.

For the Power only sites, the higher scores are more likely to yield a reduced capital requirement. CET-1 and CET Nord scored closely, and both are recommended for final site selection. CT East site is not recommended for final selection, unless additional information is provided that supports it's consideration.

7 TASK 5: LEGAL AND REGULATORY CONSIDERATIONS

7.1 INTRODUCTION / COUNTRY BACKGROUND

Moldova, officially known as Republic of Moldova, is a country in Southeast Europe, bordered by Romania to the west and Ukraine to the north, east and south. It occupies an area of 13,068 sq. mi. and has no direct access to nearby Black Sea. It is a landlocked state but has access to the Danube river on a strip of 430 meters at its southern end, through which has potential access to the Black Sea. The total population was of approximately 3.55 million citizens in 2018 (EUROSTAT, 2019a), with a density of 272 people/sq. mi.

Currently, over 92% of the total quantity of electricity produced in the Republic of Moldova (excluding the region on the left side of the Dniester) constitutes the electricity produced through cogeneration in the three existing district heating power plants (hereinafter - CET). Their electricity production depends on the thermal load of consumption in district heating systems (hereinafter - SACET) in the Chisinau and Bălți municipalities. These power plants are used at a relatively high level only during the cold season, when their capacity is used at a load factor of 24-56%, ensuring 38% of the maximum electric load of the national power system, while in the other periods of the year the production capacity of the CETs is used at a level of only 1-13%, which provides at most 11% of the maximum electric load of the power system.

The main causes that currently limit the number of available options for electricity supply are the lack of sufficient local electricity production capacities and, respectively, the lack of a competitive local electricity market; the absence of a liberalized market for the supply of electricity from Ukraine, whose system is connected with the national electricity system, as well as the impossibility of purchasing electricity from the EU market because the national electricity system is not interconnected with the European electricity system (ENTSO-E system) [50].

With the entry into force of Law 107/2016, the concept of the electricity market has been fundamentally changed by introducing organized electricity markets. In order to guarantee the security of electricity supply, when fully integrated into the market structure, short-term markets and pricing based on market mechanisms will help eliminate other measures that have a distorting effect on the market, such as market capacity mechanisms. According to ANRE, pricing based on market mechanisms without capping the prices on the wholesale market should not affect the possibility of end consumers, especially households, small and medium-sized enterprises (SMEs) and industrial consumers to benefit from prices set under conditions of stability.

Exhibit 156 - Moldova in Europe

Source: Deloitte

In the disintegration process of the Soviet Union, Moldova declared its independence on August 27, 1991. Since July 29, 1994, when its constitution was adopted, Moldova has been a parliamentary republic with a president as head of state and a prime minister as head of government. The territory of Moldova located on the eastern bank of the Dniester River (with a light green/ yellow on the map) is under de facto control of the separatist regime in Transnistria.

According to World Bank, the size of the national economy is 11.3 bn. USD [51] (GDP, current prices), equivalent to a GDP/ capita in current prices of 2,724 USD in 2018.

The average nominal monthly wages and salaries in Moldova were 306 [52] USD in 2018 (NBSRM, 2019). The average monthly salary earning of an employee in the production and supply of electricity and heat, gas, hot water and air conditioning was 528 USD for men and 488 USD for women (NBSRM, 2019). According to the same source, 5.8 thousand people were employed in this sector in 2018 by public entities and 5.6 thousand people by private companies.

From an energy perspective, Moldova's annual primary production added up to only 798 thousand toe in 2018, for all energy products. To match the gross inland energy consumption of the country, net imports were 2,109 toe, almost three times higher than domestic production. Electricity generation was (and remains) insignificant (NBSRM, 2019). The following table illustrates the complete energy balance of the country for 2018.

Exhibit 157 – The complete energy balance of Moldova, 2018

Category	Thousands of tons of oil equivalent
Primary Production	798
From other sources	219
Imports	2,109
Exports	27
Stock changes	12
Gross internal consumption	3,087
Transformation, input	430
Transformation, output	345
Energy sector	16
Losses	124
Final consumption	2,786
Industry	251
Transport	758
Other activities	1,777
Residential sector	1,385
Trade and public services	283
Agriculture / Forestry	109
Non-energy use	76

Source: NBSRM, 2019

The current energy environment of the Republic of Moldova is characterized by multiple active geopolitical influences originated from Region's recent historical evolution. From the former USSR disintegration processes in the early 90's to the modern days efforts of Russian Federation to maintain control using economic, social and political influence(s), the RoM continues to struggle to align the vital economic sectors, energy included, to the modern standards expected by European Union.

From an energy-strategy point of view, RoM is fully dependent on imports; the main imported resource is the natural gas (more than 99%). As a result, electricity and heat production is also fully dependent on the gas delivery continuity; furthermore, the main power generation plant is located within the self-proclaimed dissident Republic of Transnistria [53]. This requires in turn legal and regulatory RoM authorities' efforts to promote additional capacity build-up while the self-proclaimed Republic of Transnistria authorities use any means to block these efforts.

In the process of considering a new power capacity, and dependent on the technology choice, RoM authorities and investors should pay particular attention to the water resources/ availability. According to the Strategy for water supply and sanitation (2014 – 2028) [54], the availability of water resources in the Republic of Moldova is a critical aspect that affects the country's capacity for economic development (available water of about 500 m^3 per inhabitant per year or less in comparison with internationally recommended thresholds that define the volume of 1,700 m^3/inhabitant/year; if the volume of available water is less than 1,000 m^3/ inhabitant/year, the lack of water can impede economic development and can affect the health and standard of living of the population).

Particular attention should be also extended to the climate change issues, especially concerning the emissions reductions.

RoM undertakes to abide by ("Intended nationally determined contribution" - INDC for the Paris Climate Agreement) the commitment to achieve, by 2030, the unconditional target of 64% reduction of net greenhouse gas emissions compared to 1990 levels. The commitment to reduce emissions could increase up to 78% conditionally - in accordance with a global agreement, which would address important issues, such as providing financial resources, technology transfers and technical cooperation, and access to these to an extent commensurate with the challenges of global climate change.

The Association Agreement between the Republic of Moldova, on the one hand, and the European Union and the European Atomic Energy Community and their Member States, on the other, entails the drafting and ratification by the Republic of Moldova of a low - carbon dioxide emission development strategy and long-term measures to reduce greenhouse gas emissions.

The national inventory report: 1990-2013, sources of emissions and removals in the Republic of Moldova (2016) reveals a decreasing trend in terms of direct emissions of greenhouse gases. Between 1990 and 2013, the respective emissions declined nationally by about 70.4 percent: from 43.4188 Mt CO_2 equivalent in 1990 to 12.8363Mt CO_2 equivalent in 2013.

The energy sector is the most important source of national direct greenhouse gas emissions (without the contribution of the sector the land use, land use changes and forestry), its share varying between minimum 62.2% in 2000 and maximum 79.5 % in 1990 (over the last ten years the share of this sector has increased - in 2013, it constituted about 65.5% of the national direct emissions of greenhouse gases).

However, the medium-term forecasts carried out in accordance with the baseline scenario of greenhouse gas emissions were developed within the First updated biennial report of the Republic of Moldova, presented to the United Nations Framework Convention on Climate Change (2016), which was drawn up based on a series of strategic documents, as well as on updated data provided by ministries, central public administration authorities and institutions in the field of research and development.

The historical and forecasted reference level of greenhouse gas emissions by energy sectors, according to the baseline scenario, 1990-2030

Exhibit 158 - The evolution of greenhouse gas emissions by sector [Million t CO2 equivalent]

Years	1990	1995	2000	2005	2010	2015	2020	2025	2030
Historical values							**Forecasted values**		
Energy	34.52	11.72	6.67	8.47	8.87	8.75	9.38	10.53	12.08

Source: Development strategy development with low emissions until 2030 of the Republic of Moldova

7.2 LEGAL AND REGULATORY ANALYSIS

The objective of this study is to support Moldova's economic growth, through improving the security and availability of the energy supply, which can be achieved through increasing the country's power or heat and power generation capacity. To this end, this analysis includes legal and regulatory considerations related to the construction and operation of a potential new power plant investment.

At national level, the legal and regulatory framework consists of:

- Primary legislation (e.g. laws such as Energy Law No. 174/2017, Electricity Law No. 107/2016)
- Secondary legislation (such as norms for the legal provisions' implementation using a focused approach; e.g. ANRE decisions, orders and methodologies)

7.2.1 LEGAL ANALYSIS

INTRODUCTION

The main objective of this analysis is to define the legislative framework relevant for new or increased electricity generation capacities and to identify legal or regulatory areas which are not clearly or directly defined.

As a Contracting Party to the Energy Community Treaty, Moldova has the obligation to implement the energy acquis in force [55]. Parallel to the adoption of secondary legislation, the implementation of the acquis gives rise to diverse reporting obligations.

Particularly the implementation of the renewable energy and energy efficiency acquis is based on comprehensive, multi-annual action plans. As a first step, the Parties draft and adopt the action plans that set the steps for achieving the negotiated targets. They are subsequently obliged to report about the progress achieved in the form of regular progress reports.

Starting in 2019, Moldova will also have a reporting obligation pursuant Annex VIII.B of the Large Combustion Plan Directive 2001/80/EC as amended by Decision 2013/05/MC-EnC.

The Secretariat's assessment of Moldova's compliance with the Energy Community acquis (and for any Contracting Party's in that matter) goes beyond the mere adoption of primary legislation. In many cases, it is the adoption of secondary legislation that ensures actual implementation. Moldova must continue with the development and adoption of secondary legislation.

ASSUMPTIONS AND LIMITATIONS

Our analysis relates solely to matters of Moldovan law in force on the date hereof[56] and it is based on legislation published before this date. This analysis shall be governed by and construed and have effect in accordance with the laws of Moldova/Energy Community Treaty.

The matters expressed in this analysis as of the date hereof, are statements of opinion based on our understanding and interpretation of the laws currently in force. From our practical experience, many issues may arise in relation to the interpretation given to certain provisions of the legislation due to their often-ambiguous wording. The absence of a unitary application of the legislation may sometimes lead to contradictory decisions by the courts of law and authorities.

Each of the matters addressed in this analysis is as of the date hereof, and we hereby undertake no, and disclaim any, obligation to advise or update the present analysis further to any change in any matter set forth herein or upon which this analysis is based.

Our analysis herein takes into account the points of interest indicated by USAID and, as such, shall not be construed as exhaustive, but as strictly limited to outlining the aspects mentioned above which were agreed with the Client. Moreover, the analysis should not be interpreted as an advice on the opportunity of implementation/operation.

CURRENT SITUATION

The activity of any type of power plant (electrical, thermal, cogeneration, combined cycle), including commissioning, ongoing operations and decommissioning, is subject to national legislation and to Energy Community's policy guidelines.

Commissioning and operating a power plant in the Republic of Moldova require the observance of all relevant national legislation from the following areas:

- Authorization and permitting for the planning, construction, development and operating the cogeneration power plant
- Connection to the electricity grid
- Market registration and electricity contracting
- Permitting for heat production for a new power plant
- Specific regulations (where applies) regarding the fuel used for a new power plant
- National state aid measures (in some cases) applicable to a power plant
- Other legal aspects related to the operation of a new power plant (e.g. transferred employees, corporate aspects)
- Emissions trading
- Air, water and soil emissions monitoring
- Waste management etc.

The national primary legislation has already been adopted and covers most areas:

- Law on expropriation for a public utility cause (Law no. 488/1999)
- Regulation on the construction/reconstruction of power plants (Governmental Decision no. 436/2004)

- Law on renewable energy (Law no. 160-XVI/2007)
- Law on Ratification of Accession to EnC Treaty (Law no. 117/2009)
- Regulation of entrepreneurial activities by way of authorizations (Law no. 160/2011)
- Methodology to determine, approve and apply tariffs on the thermal energy supplied to consumers (Governmental Decision no. 482/2012)
- Law on Environmental Impact Assessment (Law no. 86/2014)
- Law on thermal energy and promoting cogeneration (Law no. 92/2014)
- Law on promoting the use of energy from renewable energy sources (Law no. 10/2016)
- Law on Electricity (Law no. 107/2016)
- Law on Natural Gas (Law no. 108/2016)
- Law on Energy (Law no. 174/2017)
- Law on declaring public utility for national interest construction works of the gas pipeline on Ungheni-Chisinau course and the implementation of some measures for operating, running and maintaining of the natural gas transport pipeline Iasi-Ungheni-Chisinau (Law no. 105/2017)
- Law on energy efficiency (Law no. 139/2018, revoking law no. 142/2010)

From the environmental compliance perspective, the list of primary/secondary legislation defining the relevant framework in Moldova comprises also:

Water:

- The Water Law no. 272 of 23 December 2011
- Government Decision no. 866 of 1 November 2013 for the approval of the Regulation regarding the procedure for drafting and revising the Hydrographical Basin District Management Plan
- Government Decision no. 932 of 20 November 2013 for the approval of the Regulation regarding the monitoring and systematic record of the status of surface water and groundwater
- Government Decision no. 955 of 3 October 2018 regarding the approval of the Management Plan for the Danube-Prut and Black Sea hydrographical basin district.
- Government Decision no. 814 of October 17, 2017 regarding the approval of the Management Plan of the Dniester hydrographical basin district [57]

Biodiversity:

- Law no. 1538/1998 on natural areas protected by the state

Waste and chemical management:

- Law no. 209 of 29.07.2016 on waste
- Law no. 277 of 29.11.2018 on chemicals
- Government Decision no. 373 of 24 April 2018 on the National Registry of Emissions and Transfer of Pollutants

Pollution prevention and environmental assessment:

- Law no. 1540 of 25.02.1998 on payment for environmental pollution

- MADRM Order no. 15 of 22.01.2019 regarding the approval of the report form (EMPOLDEP19), its filling out method, and the Instruction on how to calculate and pay for emissions and discharges of pollutants and the storage of waste

According to the aforementioned Order, the payment for the emission of pollutants into the atmosphere from stationary sources shall be collected from the subjects holding the Authorization for the emission of pollutants into the atmosphere from fixed sources and who report:

- emissions of pollutants within the limits of established norms;
- emissions of pollutants exceeding the established norms.

The payment norms for the emissions of pollutants into the atmosphere from stationary sources are established in lei for a conventional ton, depending on location:

- Chisinau and Balti municipalities - 18 lei for a conventional ton;
- other localities (including the Gagauzia autonomous territorial unit) - 14.4 lei per conventional ton.

The payment for the emissions of pollutants into the atmosphere from the stationary sources *that exceed the limits of the established norms* (Limited Admissible Emissions norms – "ELA norms") is determined, for each pollution index individually, as a sum of the product between the payment normative (from point 12) and ELA norms of pollutants (established in the Authorization for the emission of pollutants into the atmosphere from fixed sources) in conventional tonnes and of the *product between the payment norm multiplied by 5 and the real quantity of pollutants emitted which exceeds the established norms.*

- Law no. 86 of 29 May 2014 on environmental impact assessment
- MADRM Order no. 1 of 04.01.2019 regarding the approval of the Guide on carrying out the procedures regarding the environmental impact assessment

Air quality protection and climate change:

- Law no. 1422 of 17 December 1997 on atmospheric air protection;
- Law no. 78 of May 04, 2017 for the ratification of the Paris Agreement;
- Government Decision no. 1277 of 26 December 2018 regarding the establishment and operation of the National System for monitoring and reporting greenhouse gas emissions and other information relevant to climate change.

7.2.2 OWNERSHIP AND OPERATIONAL STRUCTURE OF THE POWER GENERATION ASSETS

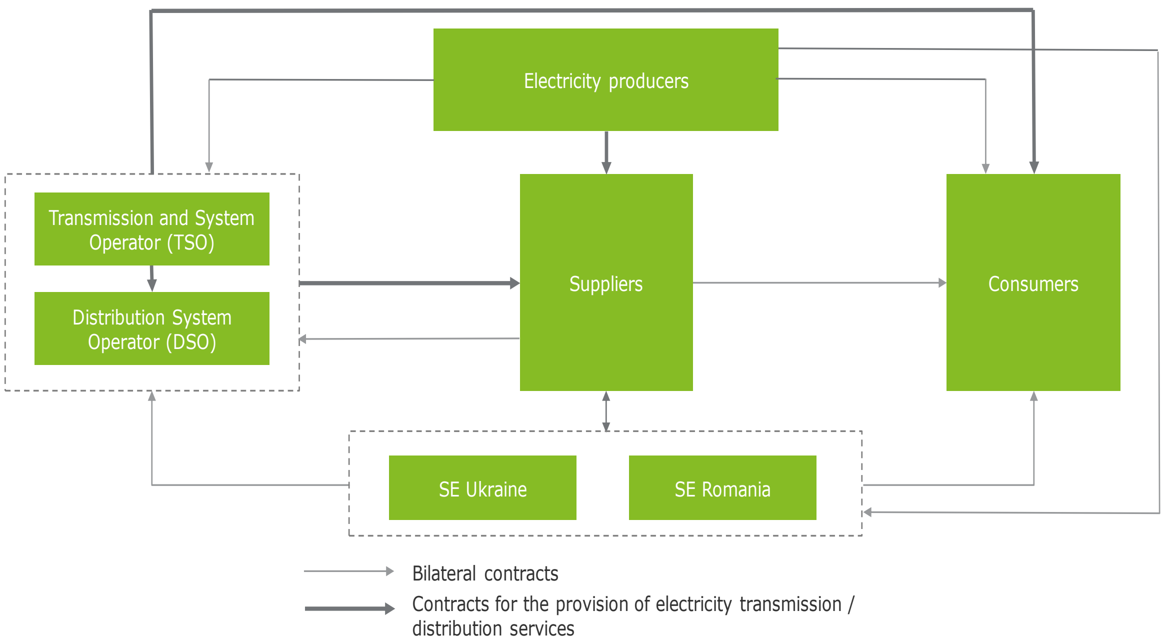
Republic of Moldova Electricity Market consists of the following participants:

- Electricity producers
- Transmission and System Operator (TSO)
- Distribution System Operators (DSOs)
- Suppliers of electricity with regulated tariffs

- Suppliers of electricity with non-regulated tariffs
- Consumers

This model is presented below:

Exhibit 159 – Electricity Market Model in Moldova

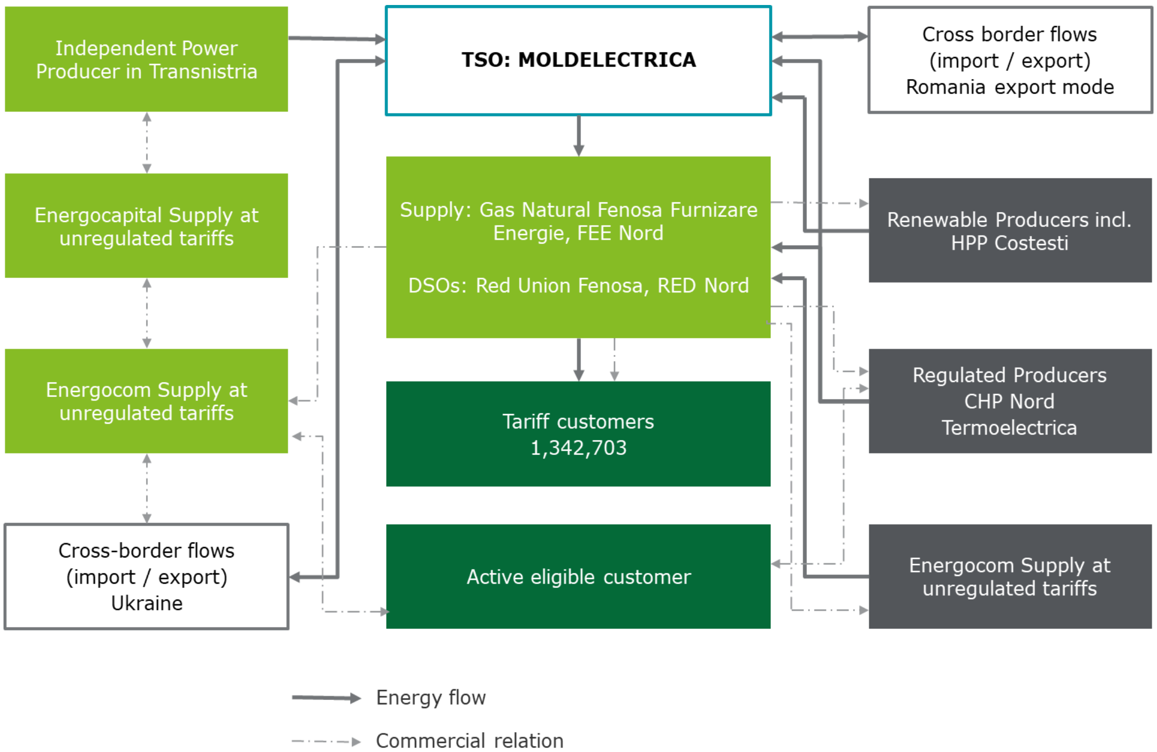


Source: Moldelectrica (http://www.moldelectrica.md/ro/electricity/energy_market_info)

Historically, a significant part of the Distribution and Supply Sector (approx. 70%[58]) has been privatized in 2000 to a strategic investor (RED Union Fenosa [59]), while the TSO has already been created the year before. Out of the resulting five Power Distribution (DSOs) entities created during this privatization process, three have merged in 2008 into Gas Natural Fenosa (GNF), while the remaining two distribution companies, covering more than 20% of the market, continue to be State Owned entities.

As Contracting Party of the Energy Community, the RoM started to implement the EU Energy Package in 2015 by separating distribution from supply activities. Hence the supply activities of the GNF were transferred to a newly established supply company called GNF FE (GNF Furnizare Energie) and the independent State-Owned entities reshuffle ended up with two new companies, one for distribution (RED Nord) and one for supply (Furnizare Energie Electrica Nord, FEE Nord) – see below the resulting Energy Sector Structure of RoM [60].

Exhibit 160 – Electricity market framework in Moldova



Source: Compiled by the Energy Community Secretariat (https://www.energy-community.org/implementation/Moldova.html)

The Energocom State Owned Company acts as an intermediary between the external entities and internal distributors and producers, as described in the general model above.

Moldova's internal power plants (not including those in the Transnistria region) generated 804 mil. kWh of electricity in 2018, covering no more than 18.7% of that year's total demand:

- Termoelectrica S.A. (CET-1 Chisinau and CET-2 Chisinau power plants) with 81% of the internal production translated into 15.1% of internal consumption
- CET-Nord with 6.7% of internal production/1.3% of internal consumption
- Costesti Hydro Power Plant with 5.4% of internal production/1.0% of internal consumption
- Other internal producers with 6.9% of internal production/1.3% internal consumption [61]

For the same year (2018), the electricity imports have supplied 81.3% of the total internal consumption (4,303.9 mil kWh).

There are also producers located on the left bank of the river Dniester, in the Transnistria region (CERS Moldoveneasca and CHE Dubasari), which have greatly contributed to Moldova meeting electricity demand in 2018 (59.1% of total demand).

Electricity delivered by CERS Moldoveneasca and CHE Dubasari (2,544 mil. kWh), is viewed as import.

The remaining 22.2% of the RoM 2018 electricity demand was met through imports from Ukraine (955.8 mil. kWh).

Exhibit 161 – 2018 Power generation and demand in Moldova (including Transnistria)

<table>
<tr><th></th><th>No.</th><th>Power Plant</th><th>Installed power capacity (MW)</th><th>Electricity delivered in 2018 (mil. kWh)</th></tr>
<tr><td rowspan="5">Internal production</td><td>1</td><td>CET-1 Chisinau</td><td>66</td><td>26</td></tr>
<tr><td>2</td><td>CET-2 Chisinau</td><td>240</td><td>625</td></tr>
<tr><td>3</td><td>CET Balti</td><td>14</td><td>54</td></tr>
<tr><td>4</td><td>CHE Costesti</td><td>16</td><td>44</td></tr>
<tr><td>5</td><td>Other sources</td><td>87</td><td>56</td></tr>
<tr><td></td><td></td><td>Total - Moldova</td><td>433</td><td>804</td></tr>
<tr><td rowspan="3">Imports</td><td>6</td><td>CERS Moldovenească</td><td>2,520</td><td rowspan="2">2,544</td></tr>
<tr><td>7</td><td>CHE Dubăsari</td><td>46</td></tr>
<tr><td>8</td><td>Imports from Ukraine</td><td>-</td><td>956</td></tr>
<tr><td colspan="3">TOTAL – Moldova (including Transnistria)</td><td>2,999</td><td>4,303.9</td></tr>
</table>

Source: Moldelectrica (http://www.moldelectrica.md/ro/electricity/energy_sources);
The Republic of Moldova ANRE report of 2018

Focusing on RoM power generation structure, it is important to note that Moldova's generation technology continues to rely heavily on gas, coal and fuel oil thermal plants, summing up to almost 3,000 MW installed power capacity (including Transnistria power plants).

From the total energy demand in 2018 (4,303.8 mil. kWh) almost 90% (3,862.7 mil. kWh) represent final energy consumption. The distribution and supply operators are:

Exhibit 162 - 2018 Electricity internal consumption

No.	Distribution and Supply Operator	Electricity purchases (mil. kWh)	% of total electricity demand
1	RED Nord [62]	85.0	2.0
2	RED Union Fenosa	243.2	5.7
3	GNF Furnizare Energie	2,767.6	64.3
4	FEE Nord	970.0	22.5
5	I.S. Moldelectrica	112.9	2.6

No.	Distribution and Supply Operator	Electricity purchases (mil. kWh)	% of total electricity demand
6	Other eligible consumers	125.1	2.9
	Total energy demand	**4,303.8**	**100**

Source: The Republic of Moldova ANRE Report of 2018

A high-level review leads to a simple conclusion: the need for electricity generation alternatives is significant from a technology, origin, geopolitical and strategic point of view.

7.3 REGULATORY ANALYSIS

7.3.1 INTRODUCTION

In July 2017, for the purpose of drafting regulatory normative acts and applying the best energy regulatory practices, the Moldovan ANRE has signed a Memorandum of Understanding with the Energy Community Secretariat to assist the Republic of Moldova on the development of important regulatory normative acts (ANRE, 2017). Consequently, the process of drafting regulatory normative acts uses the experience of the EU states and the best European practices of the energy sector regulation.

The regulatory framework of the Moldovan energy market is evolving rapidly. The main driver of change is the compulsory alignment with the Energy Community's [63] policy guidelines. These guidelines cover eight sub-sectors, namely:

- Electricity
- Cross-cutting issues (gender equality, environment, climate change, etc.)
- Regulator
- Environment
- Renewable energy
- State aid
- Energy efficiency
- Climate

7.3.2 MOLDOVAN REGULATORY FRAMEWORK OVERVIEW

Art. 12 (2) of the Energy Law no. 174 from 21.09.2017, stipulates that in order to perform the duties and functions required by law, ANRE shall elaborate and approve the regulations, methodologies and all other regulatory normative provided by the respective law and other sector specific laws. In addition, the organization and functioning Statute of ANRE, approved by the Republic of Moldova Parliamentary Decision no. 238 of 26.10.2012, stipulates that ANRE is in charge of developing and approving regulations, methodologies and any other normative acts for the energy field and for the public service of water supply and sewage.

Below is a list of the secondary legislation defining the energy framework in Moldova:

A) Regulations and methodologies

- Methodology to determine, approve and apply tariffs of electricity and thermal generation (ANRE decision no. 147/2004)
- Regulation on measuring electricity for commercial purposes (ANRE decision no. 382/2010)
- Supplying Electricity Regulation (ANRE Decision no. 393/2010)
- Methodology to determine, approve and apply tariffs for thermal energy delivered to consumers (ANRE decision no. 482/2012)
- Regulation on switching the electricity supplier by eligible consumers (ANRE decision no. 534/2013)
- Regulation on switching the natural gas supplier by final consumer (ANRE decision no. 676/2014)
- Methodology on calculating and applying natural gas regulated tariffs (ANRE decision no. 678/2014)
- Methodology to determine normative values of thermal energy losses and normative indices values for the functioning of the thermal water network (ANRE decision no. 742/2014)
- Electricity Market Regulation (ANRE Decision no. 212 /2015)
- Regulation on the quality of the electricity transport and distribution services (ANRE decision no. 282/2016)
- Regulation on access to natural gas transport and congestion management (ANRE decision no. 321/2016)
- Grid Access Regulation (ANRE decision no. 353/2016)
- Regulation on Supply of Thermal Energy (ANRE decision no. 23/2017)
- Regulation on procedures for the procurement of goods, works and services used for the license holders' activity in the electricity, thermal energy, natural gas sectors and for the operators of public water supply and sewerage service (ANRE decision no. 24/2017)
- Amendments and additions to: (ANRE decision no.57/2017)
    - Methodology for calculation, approval and adjustment of the tariffs for the electricity distribution service
    - Methodology for calculation, approval and adjustment of the regulated prices of electricity supply by the provider of the last resort and for the universal service provider
    - Methodology calculating the regulated tariffs and prices for natural gas, approval and application mechanisms
- Regulation on the Guarantee of Origin for electricity produced under high-efficiency cogeneration (ANRE decision no. 201/2017)
- Methodology for determining the fixed tariffs and the price for electricity produced from renewable energy sources, by eligible producers (ANRE decision no. 375/2017)
- Regulation on Guarantee of Origin for Electricity Produced from Renewable Energy Sources (ANRE decision no. 376/2017)
- Regulation on the way of monitoring compliance programs (ANRE decision no. 482/2017)
- Methodology for calculating, approving and applying the regulated electricity prices provided by the central electricity supplier (ANRE decision no. 483/2017)
- Regulation on Quality Parameters for Heating Distribution and Supply (ANRE decision no. 484/2017)
- Methodology for calculating, approving and applying the regulated tariffs for the electricity transmission service (ANRE decision no. 486/2017)

- Methodology for calculating, approving and applying tariffs for the electricity distribution service (ANRE decision no. 64/2018)
- Methodology for calculating, approving and applying regulated prices for electricity supplied by the final option supplier and universal service supplier (ANRE decision no. 65/2018)
- Methodology for calculating the tariff for the operation of the closed natural gas distribution system (ANRE decision no. 137/2018)
- Regulation on the development of natural gas distribution networks (ANRE decision no. 138/2018)
- Methodology to calculate, approve and apply regulated tariffs for ancillary services provided by system operators from the electricity sector (ANRE decision no. 269/2018)
- Methodology for calculation, approval and application of the regulated tariffs for the auxiliary services provided by the system operators in the natural gas sector (ANRE decision no. 271/2018)
- Regulation on the closed natural gas distribution system (ANRE decision no. 285/2018)
- Regulation on the procedures for the submission and examination of holders' license applications for regulated prices and tariffs (ANRE decision no. 286/2018)
- Regulation on Dispatch Control of the Power System (ANRE decision no. 316/2018)
- Methodology to calculate the tariff for operating the closed electricity distribution system (ANRE decision no. 317/2018)
- Regulation on the closed electricity distribution system (ANRE decision no. 48/2019)
- Regulation on the development of the electricity distribution network (ANRE decision no. 94/2019)
- Regulation on natural gas network connection and providing natural gas transport and distribution services (ANRE decision no. 112/2019)
- Regulation on natural gas supply (ANRE decision no. 113/2019)
- Regulation on the connection to the electric networks and supply of transmission services (ANRE decision no. 168/2019)
- Natural gas network code (approved in Nov. 2019 by ANRE Board of Directors)
- Electrical energy network code (approved in Nov. 2019 by ANRE Board of Directors)
- Natural gas market rules (approved on Dec. 27, 2019 by ANRE Board of Directors)

B) Technical norms

- Instructions on calculating technological own consumption in the distribution networks, depending on the value of the power factor in consumers' electrical installation (ANRE decision no. 89/2003)
- Instructions on calculating losses of active and reactive electricity in network elements included in the consumer's balance (ANRE decision no. 246/2007)
- Technical norms of the electricity transport network (ANRE decision no. 266/2007 updated by ANRE decision no. 210/2015)
- Technical norms of the electricity distribution networks (ANRE decision no. 267/2007)
- Technical norms of the natural gas transport network (ANRE decision no. 375/2010)
- Technical norms of the heating network (ANRE decision no. 136/2018)

7.3.3 REGULATION OF PRICES AND TARIFFS

THE REGULATED PRICES AND TARIFFS SET-UP & UPDATE PROCESS

In order to establish the justified and necessary costs for production of electricity and thermal energy, the regulated prices of 2015 were considered base value. Similarly, Termoelectrica S.A. distribution costs of the thermal energy supply service for the consumers was considered the base value.

Based on the ANRE analysis on the consumption and for the costs claims by licensees of the electricity, natural gas and thermoelectric sectors, in order to adjust the tariffs to reflect the real costs, in 2018, ANRE issued new electricity tariffs, tariffs for heat supplied to consumers and tariffs for electricity produced from renewable energy sources.

The ANRE Decision no. 482/2012, defines the methodology on calculating tariffs for the thermal energy supplied to consumers by operators which ensure consumer supply. Considering Termoelectrica is a vertically integrated energy cogeneration company (generation of electricity and heat, and transport and distribution of heat), a special methodology for calculating tariffs should be developed both for the electricity as well as the heat it produces.

NATURAL GAS TARIFFS

During 2017, there were no requests to ANRE to adjust the regulated prices and tariffs for natural gas. Thus, during the considered period, the average gas price determined by ANRE for 2016 was deemed valid at 5,545 lei/ 1,000 m^3.

In 2018, the average gas price determined by ANRE fell by 20.3%, reaching 4,420 lei/1000 m3. The fall in prices for natural gas supplied at regulated prices by the supplier S.A. "Moldovagaz" was caused by a number of factors, the most important being the decrease of the average annual price of gas procurement imported natural gas, the size for the year 2018 notified by S.A. "Moldovagaz" being 10.6% lower compared to the one in the previous tariff. Another important factor was the change in the exchange rate of the national currency against the USD.

TARIFFS FOR GENERATION OF ELECTRICITY, THERMAL ENERGY AND THE SUPPLY OF THERMAL ENERGY TO CONSUMERS

During 2018, the Agency adopted 12 decisions approving the tariffs for the production of electricity for wind and photovoltaic installations. The total RES generation capacity as of 31.12.2017 was 37.424 MW (29.33 MW wind, 5.709 MW biogas, 2.131 MW photovoltaic and 0.254 MW hydro).

All RES producers are connected to distribution networks, with the exception of ICS Covoare Lux SRL power plant, which is directly connected to the IS Moldelectrica transmission network.

The 2018 tariffs for electricity and thermal energy remained unchanged compared to 2017. Accordingly, the 2018 tariffs for CET Nord S.A. were set to 0.101 USD (2018 exchange rate)/ kWh for electricity and to 72.62 USD (2018 exchange rate)/ Gcal for the thermal energy. In the same year, the thermal energy tariffs for Termoelectrica S.A. were set to 66.79 USD / Gcal.

The only exception in 2018 was I.M. Servicii Municipale Glodeni, for which ANRE approved thermal energy tariffs for the first time. These were set at 72.59 USD/Gcal.

ELECTRICITY PRICES

In March 2018, ANRE has established tariffs for the power distribution service provided by the ICS RED Union Fenosa S.A. and RED Nord S.A. (RED Nord-Vest S.A. was since absorbed by RED Nord S.A.), differentiated according to the voltage category of the electrical distribution networks.

ANRE also has set regulated prices for the electricity supply of the ICS Gas Natural Fenosa Furnizare Energie S.R.L. (GNFFE) and Furnizarea Energiei Electrice Nord S.A. (FEE), differentiated by delimitation points or end-user consumption locations.

The average price of electricity supplied to the end users of ICS Gas Natural Fenosa Furnizare Energie S.R.L. was set at 0.103 USD (2018)/ kWh in July 2018.

The average electricity price supplied to the end users of Furnizarea Energiei Electrice Nord S.A. was set to 0.107 USD (2018)/ kWh in July 2018.

According to the most recent activity report (2018), ANRE has focused also on improving the mechanism that sets the retail prices for the main petroleum products. This mechanism provides a direct correlation between petrol and diesel prices on the domestic market and the evolution of regional and international stock prices. The implementation of this mechanism has contributed to stimulating competition among oil market operators, increasing the efficiency of their activities, eliminating non-transparent pricing practices for fuels.

7.4 CHANGES AND IMPROVEMENTS NEEDED TO ACCOMMODATE NEW POWER GENERATION ASSET

Below is a list of the most relevant secondary legislation with which a new power plant project would need to comply, and which is not directly addressed by existing regulation:

- Electricity wholesale market rules
- Regulation on tendering for new generation capacities
- The requirements for the minimum reserves of fossil fuels for power plants operation
- Regulation on emergencies in the electricity market and the contingency plan in emergency situations in the energy market
- General terms and conditions of electricity supply agreements of the universal service supplier and last resort supplier to end customers
- Appointment of the electricity market operator
- Methodology for the calculation, approval and application of regulated tariffs for the service of electricity market operation
- Methodology for calculation of fees for the imbalances
- Regulation on reporting to the ANRE by the licensees

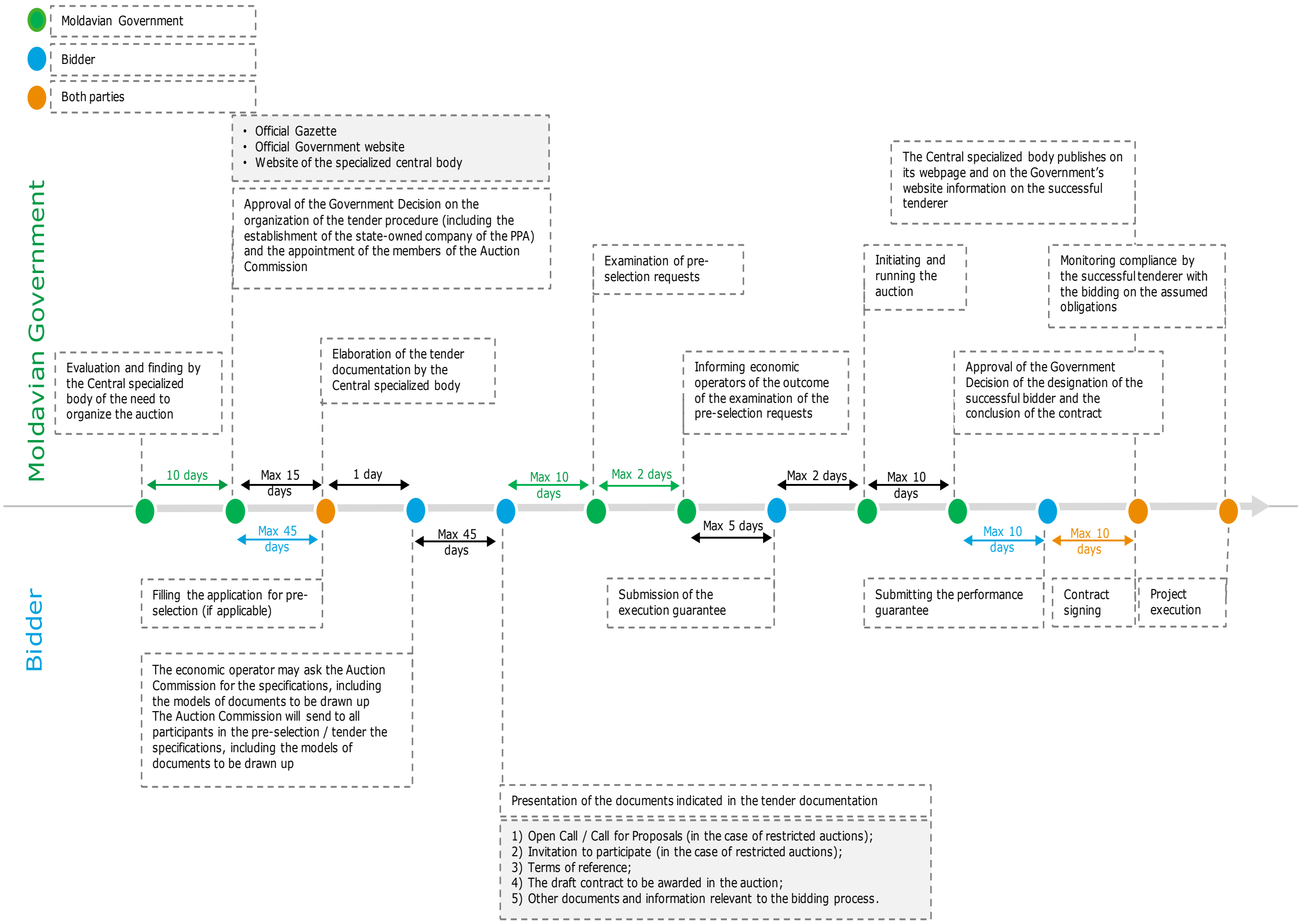
7.5 PROPOSAL FOR IMPROVING THE TENDERING REGULATION

One of the options considered in our analysis refers to the support provided to a potential Investor via a tender for the construction of new capacities or for increasing existing power generation capacities.

In this case, the following points should be addressed/revised by the Moldovan Government ("the Government") regarding the principles, clarity and phrasing of the "Regulations on conducting tenders for the construction of new capacities or for increasing existing power generation capacities" ("the Regulations"):

- In the case of a Build-Own-Operate contract, which will be the entity the Government will designate to buy the electricity produced by the power plant?
- In the case of a PPA, what will happen with the ownership of the plant after the end of the agreement?
- What are the means by which the investor is protected from the changes in the political will?
- What steps will the Government take to ensure a transparent, objective and just tender procedure?
- What international arbitration institutions and courts of law is Moldova part of?
- For the process to take place faster, we propose setting maximum durations for each step. An example of such an improvement is shown with red in the following timeline:

Exhibit 163 - Proposed maximum duration of steps for the process of increasing existing power capacities



Source: Deloitte analysis

For more information regarding the regulatory specifics surrounding tenders for the construction of new capacities or for increasing existing power generation capacities, please see Appendix 2.

7.6 IMPACT OF EXPECTED MARKET DESIGN DEVELOPMENTS

INTRODUCTION

This section will outline the regulatory proposals regarding the design of the Moldovan electricity market and will present their possible implications for the construction of new power generation units.

7.6.1 REGULATORY PROPOSALS AND PRELIMINARY IMPACT ASSESSMENT

We understand that currently there is an ongoing process to amend the Electricity Law 107/2016, as well as to draft new electricity market rules. Both documents are of paramount importance for a new power generation capacity.

Below, we have highlighted the new key provisions (based on publicly available data), as well as our recommendations.

REVISION OF ELECTRICITY LAW 107/2016

The current or adjusted Law 107/2016 provisions, corroborated with draft Electricity Market Rules (EMR) principles set out in the impact assessment, will provide current power generation units (District Heating Power Plants/ RES units/ CERS Moldoveneasca) with a more favorable regulatory framework, in the following areas:

- **New capacities** (as per art. 21, para.6 Law 107/2016 provisions): "In the case of the auction being launched for necessary generation capacities, bids for the supply of electricity with long-term guarantees, coming from existing producers, must be considered, provided that these allow additional electricity needs to be covered.
- **Existing capacities (District Heating Power Plants/ RES units)** (as per art. 30, para.3 Law 107/2016 provisions) are granted priority by the TSO in the dispatching process: "The dispatch of power plants and the use of interconnection capacities shall occur according to objective criteria, published and applied in a non-discriminatory manner, which ensure the adequate functioning of the electricity market, taking into account the economic priority of electricity coming from power plants, contracts notified by electricity market participants or the transfer of energy through interconnections, and technical constraints of the transmission network, giving priority to electricity produced in district heating power plants and electricity from eligible power plants with production from renewable energy sources.
- **Existing capacities (District Heating Power Plants/ RES units**) (as per art. 83, para. 4 and art. 86 para. 2 a) Law 107/2016 provisions) are granted regulated prices (with a certain IRR embedded) and benefit from the obligation of the Central Supplier to purchase their output.

In addition, given the considerations outlined in the impact assessment document, it appears that a new Investor would have to consider that the new market design will allow the recovery of its investment based purely on the market mechanisms.

Going forward, it is essential to understand if EMR would allow an execution of long term PPAs that would facilitate the financing arrangement (should funds like bank loans be used to finance the construction) and if it would be possible for Developer to conclude a legally binding PPA even before ANRE grants the Generation License.

DRAFT RULES OF THE ELECTRICITY MARKET

On 16 September 2019, ANRE initiated the launch of public consultations on the draft Rules of the electricity market. According to the Impact Assessment, the regulatory intervention aims to implement the objectives established in Law no. 107 of 27.05.2016 on electricity, namely ensuring a fully functioning liberalized market, security of electricity supply, transparency of decision-making, clear and non-discriminatory pricing conditions for electricity and the integration of the national electricity market into the regional and European markets.

The key principles of market organization shall establish that electricity prices are set based on supply and demand. These prices should indicate the need for electricity in real time, providing market-based incentives for investments in electricity sources with increased flexibility, interconnections, demand-response or energy storage.

The elaboration of the draft Rules of the electricity market has the aim of implementing the provisions of the Law on electricity, so that the participants in the wholesale market of electricity are able to purchase electricity under the conditions of a free energy market.

As a result of the regulatory intervention, the main benefits would be:

- Ensuring greater transparency regarding the access of system users to the electricity transmission and distribution networks and excluding the possible situations of abuse and discrimination coming from the network operators, in relation to the conclusion of the contracts for the provision of the transport and distribution services of the electricity, including by establishing a term for the conclusion of the contracts;
- The electricity market will be able to generate clear signals for investors regarding development opportunities;
- The national power system will be able to operate in conditions of safety and reliability, so as to guarantee the security of the electricity supply of the final consumers;
- The market structure will allow the coupling with the markets of the neighboring states, and subsequently the integration into the European electricity market.

In particular, in our preliminary view, the following considerations should be addressed especially in relation to the market set-up:

- Market participants' compulsory participation to the organized markets (including the Day-Ahead Market);
- Obligations of market participants to offer a certain volume of electricity generated (in correlation with their other bilateral contracts commitments, if any);
- Obligations of market participants to offer energy at a cap price.

Electricity market rules design have also been addressed through a study conducted for World Bank Report [64]. As the Report's Executive Summary reads, "(…) implementation of a liberalized electricity market in Moldova is seriously challenged by the very limited generation capacity on the right bank".

Moreover, "unfortunately, this situation will not change fundamentally even after construction of the planned HVDC interconnection, irrespective of whether a 300 MW or 600 MW is built. Consequently, it would seem almost impossible to implement a functioning wholesale electricity market without taking some precautions to limit a potential abuse of market power by MGRES"

World Bank's sponsored Report's proposed market design outlines the fact that in the future Moldova will rely on imports from Romania, Ukraine and deliveries from MGRES, preserving the status quo.

7.7 STEPS FOR COMPLIANCE WITH ALL REQUIREMENTS

7.7.1 COMPLIANCE OBLIGATION

Energy Community Accession [65] – Compliance Obligations:

- Directive 2003/54/EC concerning common rules for the internal market in electricity – by 31 December 2009
- Directive 2003/55/EC concerning common rules for the internal market in natural gas – by 31 December 2009
- Regulation no. 1775/2005 on conditions for access to the natural gas transmission networks – by 31 December 2010
- Directive 2004/67/EC concerning measures to safeguard security of natural gas supply – by 31 December 2010
- Regulation 1228/2003 on conditions for access to the network for cross border exchanges in electricity – by 31 December 2010
- Commission Decision 2006/770/EC amending the Annex to Regulation no 1228/2003 on conditions for access to the network for cross-border exchanges in electricity – by 31 December 2010
- Directive 2005/89/EC concerning measures to safeguard security of electricity supply and infrastructure investment - By 31 December 2010
- Directive 85/337/EEC on the assessment of the effects of certain public and private projects on the environment, as amended by Directive 97/11/ EC and Directive 2003/35/EC – by 31 December 2010
- Plan for the implementation of Directive 2001/77/EEC on the promotion of electricity produced from renewable energy sources in the internal electricity market – by 31 December 2010
- Plan for the implementation of Directive 2003/30/EC on the promotion of the use of biofuels or other renewable fuels for transport – by 31 December 2010
- Directive 79/409/EC, Article 4(2), on the conservation of wild birds – by 31 December 2010
- Directive 1999/32/EC relating to a reduction in the Sulphur content of certain liquid fuels – by 31 December 2014
- Directive 2001/80/EC on the limitation of emissions of certain pollutants into the air from large combustion plants – by 31 December 2017

In addition, through the adoption of the Gas and Electricity Network Codes, RoM will transpose the following Regulations and Directives into national legislation:

- Regulation 2016/631/EU establishing a network code on requirements for grid connection of generators

- Regulation 2016/1447/EU establishing a network code on requirements for grid connection of high voltage direct current systems and direct current-connected power park modules
- Regulation 2016/1388/EU establishing a Network Code on Demand Connection
- Regulation 2015/703/EU establishing a network code on interoperability and data exchange rules
- Regulation 2017/459/EU establishing a network code on capacity allocation mechanisms in gas transmission systems and repealing Regulation (EU) No 984/2013
- Regulation 2017/460/EU establishing a network code on harmonized transmission tariff structures for gas

7.7.2 STATUS OF COMPLIANCE

The Republic of Moldova authorities have signaled their commitment to continue the energy sector reform and the electricity market establishment. A sector reform program was agreed with international partners' operational and financial support (EBRD, EIB, EU, EnCS, and WB) [66]. The program titled Power Sector Action Plan (PowerSAP) that aims to create a competitive electricity market in Moldova while ensuring cost recovery, will promote and support reform agenda, draft the Wholesale Electricity Market rules and review transmission tariffs.

The ongoing "Energy Sector Management Advisory Program" funded by World Bank [67] should most likely conclude in 2019 and should identify the optimal electricity market design to achieve competitive and transparent electricity sector environment.

According to the 2018 Implementation Report issued by the Energy Community Secretariat, assessing the contracting parties' implementation of the Treaty [68] acquis, the Republic of Moldova has made some progress but still need to catch up, having an overall implementation score of 44%, with electricity sector still at an early stage (41% implementation score) [69].

Exhibit 164 – Summary overall implementation of the Third Energy Package in Moldova (44%)

Summary Indicators	Implementation Status	Descriptions
Electricity	41%	Implementation in the electricity sector of Moldova is still at an early stage
Gas	31%	Implementation in the gas sector of Moldova is still at an early stage
Renewable Energy	69%	Implementation in the renewable energy sector of Moldova is well advanced
Energy Efficiency	74%	Implementation in the energy efficiency sector of Moldova is well advanced
Environment	64%	Implementation in the environment sector of Moldova is moderately advanced
Climate	19%	Implementation in the climate sector of Moldova is yet to begin
Infrastructure	21%	Implementation in the infrastructure sector of Moldova is yet to begin
Statistics	90%	Implementation in the statistics sector of Moldova is almost complete

Source: Energy Community Secretariat 2019 Annual Implementation Report

With respect to the implementation of the Third Energy Package, Moldova has taken steps in the right direction, through the adoption of the Electricity law, steps which include the beginning of the electricity TSO's unbundling process and the endorsing of the wholesale market concept. The Electricity Law transposes the unbundling requirements of Directive 2009/72/EC.

According to the Electricity law, the decision to unbundle generation and supply activities of Moldelectrica was adopted by the Government in August 2018.

Although the three DSOs are also legally separated from supply, their actual functional unbundling is still to be finalized.

In April 2019, the Government adopted the Regulation on Emergencies on the Natural Gas Market, together with an Action Plan for Emergencies on the Natural Gas Market. ANRE has also approved the Regulation on supply of natural gas, including the Standard Clauses of Contracts on Supply of Natural Gas of Last-Resort.

A new unbundling plan, opting for an independent transmission operator model (ITO) was produced in cooperation with the Secretariat and is under discussion as of August 2019.

In November 2019, ANRE adopted a natural gas code and a Regulation on access to the natural gas transmission networks and congestion management that transpose the gas and electricity Network Code Regulations.

Exhibit 165 - Overall implementation score on electricity (41%)

Electricity Indicators	Implementation Status	Descriptions
Unbundling	47%	• The Government adopted an unbundling decision for Moldelectrica in August 2018 enabling the company to apply to the regulator for certification under the Third Energy Package rules • Functional unbundling of the DSOs has to be finalized for all private and state-owned companies.
Access to networks	52%	• The tariffs are approved and published • Allocation of cross-border capacities with the Ukrainian system are not performed based on market principles and fail to comply with Regulation (EC) 714/2009 • ANRE adopts an electricity network code; a Regulation on access to the electricity transmission networks for cross-border exchanges and congestion management in the power system; and a Regulation on access to the natural gas transmission networks and congestion management that transpose the gas and electricity Network Code Regulations
Wholesale market	41%	• Wholesale electricity prices are market-based except for the domestic combined heat and power plants • The day-ahead and balancing markets, as well as their transparency, are still to be implemented
Retail market	59%	• All customers are eligible, nevertheless, regulated supply services are still accessible to all customers
Regional integration	7%	• There is no bilateral market integration with Ukraine yet due to delays in market reforms in both countries • The interconnection project with Romania has advanced with the endorsement of the loan agreements by the Government • Connection Network Codes are yet to be transposed

Source: Energy Community Secretariat 2019 Annual Implementation Report

A vast majority of the Third Energy Package was transposed through the adoption of the Law on Natural Gas in 2016. Since then, the main secondary legislation was drafted with support from the Energy Community Secretariat, with only few legal acts actually being adopted to date.

7.8 POTENTIAL ROADBLOCKS / DIFFICULTIES

7.8.1 SUPPLY CHAIN ISSUES

- The new Gas Market Rules provide for the option of a long-term bilateral contract and new gas supply routes (Trans-Balkan corridor, reverse flow operational starting with January 2020) have emerged or shall emerge (Vestmoldtransgaz pipeline); however, the Investor and RoM should agree beforehand on a gas procurement strategy that would minimize the impact on variable costs (fuel).
- The High Voltage Interconnections with EU is still in planning phase, so the energy export options are limited – a risk any future operator should be concerned with; on the other hand, power imports from Romania at least should be assessed through the latest adequacy study results – which indicate a lack of generation on the Romanian power system.
- Electricity market design not in place yet – the commercial model applicability is limited, and the risk of dumping/capped prices will have to be considered.
- The usage of other sources for power generation is limited due to availability and environmental constraints (e.g. hydro, coal) or network integration (wind as a variable source needs flexibility which cannot be provided through generation or demand-response, in the current conditions)

7.8.2 LEGAL ROADBLOCKS

The build-up / construction phase might encounter delays. A special framework for Projects of National Interest would help controlling the calendar and the costs:

- Temporary or permanent usage rights for publicly owned lands needed for power plants access or operations should be granted without renting or other compensatory costs (i.e. lost revenue) during the entire period of utilization.
- Temporary or permanent usage rights for privately owned lands needed for power plants access or operations should be compensated for renting and other lost revenues, based on mutual agreement with the owner.
- If the agreement above cannot be reached in due time for any reason (i.e. unknown owner, unclear legal status, etc.) the construction and the operations shall still go on, the estimated expected compensation shall be deposited in an escrow account and the issue can be subsequently settled in court.
- Once the Government declare the project "of National Interest", the construction and land permits and authorizations issued by local authority would no longer need to precede the construction and operations activities.
- The usage and access rights cannot be suspended during the operational phase.
- If special conditions apply, the usage and access rights may be established by the Government within national parks' protected & buffer zones.

- Once the operational phase ends, the land asset must be returned to the rightful owner free from any structural or environmental changes, restored to its initial status and usage.

7.8.3 STRATEGIC / OTHERS

- The regional political and strategic interests would maintain legal uncertainty for unsolved territorial issues and claims and may manipulate the market mechanisms in order to determine geopolitical gains.
- The existing limited capacity of electricity generation on the right bank of Dniester River while the majority of the supply comes from the left bank of Dniester River or from Ukraine (via power lines also crossing the left bank territory) represent a serious threat of the energy supply security for RoM.
- The Electricity Transmission Network is synchronized with the Integrated Power System (of Ukraine, Kazakhstan and other Community of Independent States) and mutually dependent of the Unified Power System of Russian. The ENTSO-E (including Romanian) system grid is neither linked nor synchronized.
- The secondary gas operator (Vestmoldtransgaz) in charge of building the new gas pipeline between Ungheni and Chisinau may not be able to start and/or complete the project aimed to diversify the as supply routes to RoM The project is expected to build until December 2019 a new 120 km pipeline able to transport up to 1.5 bn. cubic meters of gas from Romania to Chisinau.
- Issuing new water permits for new power generation projects that require cooling might also be a roadblock given, e.g., the Ukraine planned hydropower capacity to be built on the Dniester River upstream of the RoM borders. Ukraine or RoM does not evaluate the downstream implications yet.
- Location (e.g. to accommodate connections to the power grid, access to water and natural gas) and land availability would be key drivers in the economics of the greenfield power generation project. Our research indicated that a previous location considered for a large gas-fired combined cycle power plant was Burlaceni [70]
- As an alternative to a capacity market mechanism support type, or market-based mechanisms, investors might consider the Government-led programs for Public-Private Partnership (PPP). While recognizing the shortage of public funds, in order to address the under-developed services and infrastructure upgrades, the current RoM authorities display an encouraging openness to join ideas, projects and programs aim to provide effective, but still efficient, services for the population, including power generation/ supply.

8 TASK 6: TECHNOLOGY OPTIONS

8.1 BASIS OF DESIGN FOR THE NEW GENERATION CAPACITIES

The design basis is established based on data and information collected from the project stakeholders in Moldova and on electric power and heat demand projection analyses in Section 4, preliminary review of potential sites in Section 6, and on information related to long term availability of natural gas and water supply, and on issues related to the water discharge as presented in Section 5 of this report. The design basis also considers government of Moldova related strategic decisions on energy [71].

The collected, verified and established data has been utilized to develop the following design criteria for selecting target electric power and thermal capacities, and configurations for the new power and heat generation options:

1. Moldelectrica requirements
    a. A single new power generation unit capacity should not exceed 15% of the country peak power load (right bank [72]), or approximately 160 MWe.
    b. The assessment should include evaluation of an electric power only generation option capable of providing balancing power for the Moldova national power system due to foreseen additions of renewable generation capacities of approximately 160 MWe,
2. Electric power demand analysis (Section 4.4.7)
    a. Moldova right bank peak electric power load demand projection in 2030s is ranging from 912 MW to 1,023 MW. The Annual energy demand in 2030 is projected at 4964 GWh to 5563 GWh.
3. Heat demand analysis (Section 4.3.3)
    a. Chisinau district heating system is the only district heating system in Moldova that has sufficient heat load to justify a construction of a new large-scale CHP unit
    b. During the heating season, Chisinau district system operates in three loops.
        i. The main loop, approximately 70% of the Chisinau district heating system demand, is supplied by CET-2.
        ii. Approximately 30% of the Chisinau district heating system demand is supplied by CT Vest and CT Sud heat-only plants via two separate system loops.
        iii. The World Bank study [73] analyzed the hydraulic constraints of the DH system. They estimated that the CAPEX of combining the three DH system loops into a single loop during the heating season had a higher CAPEX and worse economics than the new proposed reciprocating engine units at the Sud and Vest plants. In addition, single loop operation could reduce the overall DH system reliability.
        iv. The new CHP units must be constructed while the existing CET-2, CT Vest and CT Sud units are in operation to assure uninterruptable heat supply to the Chisinau district heating system.
    c. During the off-heating season, Chisinau district heating system provides hot water service only in a single loop. Heat for the hot water service is currently generated by CET-1 in a cogeneration mode. The new CHP units must be constructed while CET-1 is in operation to assure uninterruptable hot water service to the Chisinau district heating system.

d. The new reciprocating engine units at CT Sud and CT Vest plants should be sized to provide hot water service during the off-heating season for the whole Chisinau district heating system.
e. New CHP units are to be constructed alongside of operating existing CET-2 units

4. Water supply
   a. As detailed in Section 5, Moldova has limited water resources.
   b. Raw water makeup and waste water discharge requirements for the new generating units that are to be located on the existing brownfield sites should be consistent with the currently available raw water and waste water capacities and permits at these sites.
   c. Air cooling systems, such as Air-Cooled Condenser, or Heller tower could be considered for the new generating units to be located on green-field sites.

Based on the above criteria the target technical parameters for the new generating capacities are presented in Exhibit 166.

Exhibit 166 Target Technical Parameters

Parameter	Units	Value	Notes
Total New Additional Capacity for all units	MWe, gross	650	In line with the Republic of Moldova Government Decree No 102 [71]
Max generating capacity per generator	MWe, gross	160	Approximately15% of the Right bank load [74]
Winter DH Load for CET-2 loop			2030 projection; see Load Duration Curves in Task 2
Maximum	Gcal/h	530	
Average	Gcal/h	380	
Min	Gcal/h	150	
Heating season duration	Hours	3936	
Winter DH Load for South and West Loop			2030 projection; see Load Duration Curves in Task 2
Maximum	Gcal/h	180	
Average	Gcal/h	120	
Min	Gcal/h	60	
Heating season duration	Hours	3760	
Summer DH load for Chisinau DH system (single loop)			2030 projection; see Load Duration Curves in Task 2
Maximum	Gcal/h	100	
Min	Gcal/h	50	

8.2 TECHNICAL AND ECONOMIC SCREENING ANALYSIS

8.2.1 DEVELOPMENT OF PREFERRED OPTIONS

The candidate projects considered for the technical options evaluation have been selected to meet the technical paraments *(Exhibit 166*) and other design criteria as specified in Section 8.1. The CHP Projects 1 through 4 provide a range of potential solutions for satisfying Chisinau DH system heat demand currently primarily supplied by CET-2, while co-generating power. Project 1 and Project 2 are configured to maximize electric power generation by operating in condensing mode during the off-heating season. Project 3 and Project 4 design allows for operation only during the heating season, with Project 3 equipped with a backpressure steam to maximize a fuel utilization efficiency, and Project 4 that is not equipped with a steam turbine system to minimize capital costs.

The Project 5 configuration follows the recommendations of the World bank study [2] with the installation of new RICE units. Project 6 is a state-of-the-art single shaft GTCC unit while Project 7 is a multi-shaft GTCC unit configured to meet technical criteria specified in Exhibit 166.

The gas turbine and RICE models selected for all the projects are best available state of the art technologies for the specified nominal output range and application, as these are commercially available machines with the highest reported efficiencies for the 50Hz service.

All Projects will be utilizing natural gas as a primary fuel, with the Ultra-Low Sulfur Diesel (ULSD) as a backup fuel to meet the Euro V standard for fuel. While Moldova as an EU accession country have been granted certain temporary exemptions to allow for transition to the ULSD, it is expected that Moldova will have to fully comply with the EU environmental regulations by 2030, when the projects are envisioned to be commissioned.

Descriptions of the candidate projects are presented in Exhibit 167, and a summary of the projects' technical attributes are presented in Exhibit 168

Exhibit 167 Description of Candidate Projects

Project	Description
1	A CHP plant to be located on the CET-2 site and with a nominal electric net output of approximately 480 MW, and maximum district heating capacity of 530 Gcal/h. The Project 1 plant will include three (3) model GT1 gas turbines connected to three (3) duct fired HRSG, and a single steam turbine generator. Project 1 is configured with the capability of operating in condensing mode with the steam turbine condenser cooled by an evaporative wet cooling tower. During the heating season, the Project 1 plant will be dispatched based on the heat load, while co-generating electric power. It is configured to meet the peak heat demand of Chisinau DH CET1/CET-2 loop while firing duct burners. During the off-heating season, the Project 1 plant will be dispatched based on the electric power load, while operating in condensing mode.

Project	Description
2	A CHP plant to be located on the CET-2 site and with a nominal electric net output of approximately 458 MW, and maximum district heating capacity of 477 Gcal/h. The Project 2 plant will include two (2) model GT2 gas turbines connected to two (2) duct fired HRSG, and a single steam turbine generator. Project 2 is configured with the capability of operating in condensing mode with the heat sink to the steam turbine condenser provided by an evaporative wet cooling tower. During the heating season, the Project 2 plant will be dispatched based on the DH heat load, while co-generating electric power. It is configured to meet approximately 90% of the peak heat demand of Chisinau DH CET1/CET-2 loop while firing duct burners. During the coldest ambient conditions, the balance of the DH peak demand is envisioned to be satisfied by the Hot Water Boilers. During the off-heating season, the Project 2 plant will be dispatched based on the electric power load, while operating in condensing mode.
3	A CHP plant to be located on the CET-2 site and with a nominal electric net output of approximately 453 MW, and maximum district heating capacity of 483 Gcal/h. The Project 3 plant will include two (2) model GT2 gas turbines connected to two (2) duct fired HRSG, and a single steam turbine generator. Project 3 is configured with a back-pressure steam turbine, which can only operate when there is a sufficient DH load. Project 3 plant does not require a cooling tower. During the heating season, Project 3 plant will be dispatched based on the DH heat load, while co-generating electric power. It is configured to meet approximately 97% of the peak heat demand of Chisinau DH CET1/CET-2 loop while firing duct burners. During the coldest ambient conditions, the balance of the DH peak demand is envisioned to be satisfied by the Hot Water Boilers. The Project 3 plant will not operate during the off-heating season.
4	A CHP plant to be located on the CET-2 site and with a nominal electric net output of approximately 298 MW, and maximum district heating capacity of 530 Gcal/h. The Project 4 plant will include two (2) model GT2 gas turbines connected to two (2) duct fired HRSG. The Project 4 plant will not have a steam turbine. It is envisioned to operate only when there is a sufficient DH load. The Project 4 plant does not require a cooling tower. During the heating season, the Project 4 plant will be dispatched based on the DH heat load, while co-generating electric power. It is configured to meet peak heat demand of Chisinau DH CET1/CET-2 loop while firing duct burners. The Project 4 plant will not operate during the off-heating season.

Project	Description
5	Project 5 is envisioned as two CHP plants. One of the Project 5 plants will be located on the CT Vest site and will include three (3) RICE type generators connected to three (3) WHR systems, with nominal net electric output of approximately 30 MW, and district heating capacity of 36 Gcal/h. Another Project 5 plant will be located on CT Sud site and will include two (2) RICE type generators connected to two (2) WHR systems, with nominal net electric output of approximately 20 MW, and district heating capacity of 24 Gcal/h. During the heating season, the Project 5 plants will be dispatched based on the DH heat load, while co-generating electric power. During the heating season, the RICE plant located on the CT Vest site will supply approximately 33% of the DH peak demand for the CT Vest DH loop, and the RICE plant located on the CT Sud site will supply approximately 27% of the DH peak demand for the CT Sud DH loop. The balance of the DH peak demand is envisioned to be satisfied by the Hot Water Boilers for both CT Vest and CT Sud DH loops. During the off-heating season when the Chisinau DH system operates in a single loop, the Project 5 plants will be dispatch based on the total hot water demand of the Chisinau DH system.
6	Project 6 is a GTCC unit to be located on the CET Nord site and with a nominal electric net output of approximately 150 MW. The Project 6 plant will include one (1) model GT1 gas turbine connected to one (1) steam turbine via a clutch in a single shaft configuration (i.e. GT and ST will share a single electric generator). Project 6 will also include a HRSG. Project 6 is designed to operate only in condensing mode, with the steam turbine equipped with an Air Cooled Condenser (ACC). The Project 6 plant will be dispatch based on the electric power load providing power for the Moldova national power system to balance the future renewable generation capacities. Since according to the Moldova government legislative commitment, the future renewable sources are envisioned to operate with a capacity utilization factor of 0.25, Project 6 is expected to operate with an annual capacity utilization factor of 0.75.
7	Project 7 is a GTCC unit to be located on the CET Nord site and with a nominal electric net output of approximately 219 MW. The Project 7 plant will include one (1) model GT2 gas turbine and one (1) steam turbine in a multiple shaft configuration (i.e. GT and ST each have their own electric generator to stay below the 160MW generator limit). Project 7 will also include a HRSG. Project 7 is designed to operate only in a condensing mode, with the steam turbine equipped with an Air Cooled Condenser (ACC). The Project 7 plant will be dispatch based on the electric power load providing power for the Moldova national power system to balance the future renewable generation capacities. Since according to the Moldova government legislative commitment, the future renewable sources are envisioned to operate with a capacity utilization factor of 0.25, Project 7 is expected to operate with an annual capacity utilization factor of 0.75.

Exhibit 168 Technical Attributes of Candidate Projects

Project	Cycle	Configuration	Target Site	Estimated Space, m	Nominal Output, MWe/Gcal/h	Comments
1	CHP	3GT1 x 3HRSG x 1STG (condensing)	CET-2	200 x 180	480/ 530	GT1 is assumed based on MHPS H-100
2	CHP	2GT2 x 2HRSG x 1STG (condensing)	CET-2	215 x 170	458 / 477	GT2 is assumed based on GE 9E.04
3	CHP	2GT2 x 2HRSG x 1STG (backpressure)	CET-2	215 x 140	453 / 483	
4	CHP	2GT2 x 2HRSG	CET-2	194 x 124	298 / 530	
5	CHP	2RICE x 2WHR, 3RICE x 3WHR	CT Sud CT Vest	60 x 60 70 x 60	20 / 24 30 / 36	RICE is assumed based on Jenbacher J920
6	GTCC	1GT1 x 1HRSG x 1STG	CET Nord	190 x 150	150 / 0	Single shaft configuration
7	GTCC	1GT2 x 1HRSG x 1STG	CET Nord	200 x 150	219 / 0	Multiple shaft configuration

Notes:

1. Legend
    a. CHP – Combined Heat and Power
    b. GTCC -Gas Turbine Combined Cycle
    c. RICE – Reciprocating Internal Combustion Engine;
    d. HRSG – Heat Recovery Steam Generator
    e. STG – Steam Turbine Generator
    f. WHR – Waste Heat Recovery System
2. Estimated space requirements include space for an associated switch yard.

The above projects are combined into the following options (Exhibit 169) that are configured to satisfy the target technical parameters specified in Exhibit 166. The candidate technical options are configured to utilize the same gas turbine model (GT1 or GT2) within an option to streamline future spare parts and GT maintenance services procurement, and operators' training.

Exhibit 169: Candidate Technical Options Matrix

Options	Project 1	Project 2	Project 3	Project 4	Project 5	Project 6	Project 7
Option 1	X				X	X	
Option 2		X			X		X
Option 3			X		X		X
Option 4				X	X		X

8.2.2 TECHNICAL ANALYSIS RESULTS

The performance of each project was simulated utilizing Thermoflow GTPro and GTMaster software for the following three ambient conditions which were chosen for sizing and techno-economic analysis considerations.

A. Coldest week minus 12°C (maximum district heating load),
B. Average winter conditions - 0°C (average district heating load),
C. Average summer conditions - 25°C (hot water service only).

Performance analyses for all options are based on the following inputs and assumptions. Several of these notes are cross-referenced by the technical analysis results tables that follow.

1. Performance for all projects is referenced to Chisinau site conditions (170m MSL, 60%RH) based on ASHREA data.
2. Fuel is natural gas.
3. The GT/Engine performance is based on Thermoflow software data.
4. Cogeneration efficiency is defined as: (net plant electric output + all useful heat output) / (Total fuel LHV input), exclude thermal energy and fuel consumption from hot water boilers. For a GTCC plant, the efficiency is for combined cycle efficiency.
5. The number of operating GTG's and load in the summer is limited by the available cooling capacity at the existing site.
6. The GTCC condensers for Projects 6 and 7 are based on air-cooled condensers.
7. Cooling tower makeup is based on 5 Cycles of Concentration. For the sites without condensing steam turbine, the cooling tower is sized for plant auxiliary cooling requirement.
8. Performance is based on 0.5% Boiler Blowdown.
9. GT1 can achieve 9 ppm NOx emissions, and GT2 can achieve 5 ppm NOx emissions both at 15% O_2, which should satisfy EU NOx emissions limit of 15 ppm. SCR system is not included in any projects of the GT based units.

10. The current EU standard for NOx emission for the selected size of the RICE is 95 mg/Nm^3 at 15% O_2. The selected RICE model is reported to have about 188 mg/Nm^3 of NOx emissions at 15% O_2 without an SCR system. SCR system is included in all projects utilizing RICE.

11. The assumed gas supply pressure is 3 Barg and, therefore, gas booster compressor(s) is included in the design.

A summary of the technical analysis for Option 1 is presented in Exhibit 170.

Exhibit 170 Option 1 Technical Analysis Results

Item	Description	Units	Option 1		
			Project 1	Project 5	Project 6
A. Plant Performance-Winter Max DH Load @ -12°C					
1	Number of Operating GTG//Engie		3	5	1
2	GTG/Engine Load	%	73	100	100
3	Number of Operating STG		1	0	1
4	GTG/Engie Output, each	kW	112,387	10,387	114,716
5	STG Output , each	kW	160,000	0	42,718
6	Site Gross Output	kW	497,161	51,935	157,434
7	**Site Net Output**	**kW**	**479,727**	**49,898**	**150,221**
8	Total Net Output	kW	679,846		
9	DH-Hot Water Supply from CHP, Each Site	Gcal/h	530.1	60.0	0.0
10	DH-Total Hot Water Supply from CHP, All Sites	Gcal/h	590		
11	DH-Hot Water Supply from Boilers, Each Site	Gcal/h	0	120	0
12	DH-Hot Water Supply from Boilers, All Sites	Gcal/h	120		
13	Total DH Hot Water Supply-CHP & Boilers, All Sites	Gcal/h	710		
14	GTG Fuel Input (Each Site)	GJ/h - LHV	3,119.8	399.4	1,055.9
15	HRSG Duct Burner Fuel Input (Each Site)	GJ/h - LHV	1,346.8	93.6	0.0
16	HW Boilers Fuel Input @90% Efficiency, Each Site	GJ/h - LHV	0	558.2	0.0
17	Fuel Gas Consumption-Each Site	GJ/h - LHV	4,466.6	1,051.2	1,055.9
18	Total Fuel Gas Consumption	GJ/h - LHV	6,573.6		
19	Site Cogen Efficiency (LHV) (4)	%	88.35%	87.40%	51.22%
20	Condenser Cooling Load (6)	MWth	19.00	#N/A	97.20
21	Cooling Tower Makeup (7)	t/h	20.99	21.05	#N/A
22	Steam Cycle Makeup (demin water) (8)	t/h	4.51	#N/A	0.83

Item	Description	Units	Option 1		
			Project 1	Project 5	Project 6
B. Plant Performance-Winter Normal DH Load @ 0°C					
1	Number of Operating GTG//Engie		3	5	1
2	GTG/Engine Load	%	73	100	100
3	Number of Operating STG		1	0	1
4	GTG/Engie Output, each	kW	110,175	10,387	112,410
5	STG Output , each	kW	160,000	0	45,932
6	Site Gross Output	kW	490,525	51,935	158,342
7	**Site Net Output**	**kW**	**473,570**	**49,898**	**150,899**
8	**Total Net Output**	**kW**	**674,367**		
9	DH-Hot Water Supply from CHP, Each Site	Gcal/h	380.0	60.0	0.0
10	DH-Total Hot Water Supply from CHP, All Sites	Gcal/h	440		
11	DH-Hot Water Supply from Boilers, Each Site	Gcal/h	0	60	0
12	DH-Hot Water Supply from Boilers, All Sites	Gcal/h	60		
13	Total DH Hot Water Supply-CHP & Boilers, All Sites	Gcal/h	500		
14	GTG Fuel Input (Each Site)	GJ/h - LHV	3,089.9	399.4	1,045.8
15	HRSG Duct Burner Fuel Input (Each Site)	GJ/h - LHV	830.5	93.6	0
16	HW Boilers Fuel Input @90% Efficiency, Each Site	GJ/h - LHV	0	279	0
17	Fuel Gas Consumption-Each Site	GJ/h - LHV	3,920	772	1,046
18	Total Fuel Gas Consumption	GJ/h - LHV	5,738		
19	Site Cogen Efficiency (LHV) (4)	%	84.07%	87.40%	51.95%
20	Condenser Cooling Load (6)	MWth	57.0	#N/A	97.2
21	Cooling Tower Makeup (7)	t/h	60.6	22.7	#N/A
22	Steam Cycle Makeup (demin water) (8)	t/h	3.80	#N/A	0.85

Item	Description	Units	Option 1		
			Project 1	Project 5	Project 6
C. Plant Performance-Summer Min DH Load @ 25°C					
1	Number of Operating GTG//Engie (5)		2	5	1
2	GTG/Engine Load	%	73	100	100
3	Number of Operating STG		1	0	1
4	GTG/Engie Output, each	kW	71,981	10,387	100,830
5	STG Output , each	kW	66,902	0	46,354
6	Site Gross Output	kW	210,864	51,935	147,184
7	**Site Net Output**	**kW**	**200,085**	**49,898**	**138,635**
8	**Total Net Output**	**kW**	**388,618**		
9	DH-Hot Water Supply from CHP, Each Site	Gcal/h	0	60	0
10	DH-Total Hot Water Supply from CHP, All Sites	Gcal/h	60		
11	DH-Hot Water Supply from Boilers, Each Site	Gcal/h	0	0	0
12	DH-Hot Water Supply from Boilers, All Sites	Gcal/h	0		
13	Total DH Hot Water Supply-CHP & Boilers, All Sites	Gcal/h	60.0		
14	GTG Fuel Input (Each Site)	GJ/h - LHV	1,496.6	399.4	970.8
15	HRSG Duct Burner Fuel Input (Each Site)	GJ/h - LHV	0.0	93.6	0.0
16	HW Boilers Fuel Input @90% Efficiency, Each Site	GJ/h - LHV	0	0	0
17	Fuel Gas Consumption-Each Site	GJ/h - LHV	1,496.6	493.0	970.8
18	Total Fuel Gas Consumption	GJ/h - LHV	2,960		
19	Site Cogen Efficiency (LHV) (4)	%	48.13%	87.40%	51.41%
20	Condenser Cooling Load (6)	MWth	157	#N/A	100.6
21	Cooling Tower Makeup (7)	t/h	251.6	27.1	#N/A
22	Steam Cycle Makeup (demin water) (8)	t/h	1.28	#N/A	0.85

A summary of the technical analysis for Option 2 is presented in Exhibit 171.

Exhibit 171 Option 2 Technical Analysis Results

Item	Description	Units	Option 2		
			Project 2	Project 5	Project 7
A. Plant Performance-Winter Max DH Load @ -12°C					
1	Number of Operating GTG//Engie		2	5	1
2	GTG/Engine Load	%	100	100	100
3	Number of Operating STG		1	0	1
4	GTG/Engie Output, each	kW	156,567	10,387	159,735
5	STG Output , each	kW	160,000	0	68,700
6	Site Gross Output	kW	473,134	51,935	228,435
7	**Site Net Output**	**kW**	**457,581**	**49,898**	**218,710**
8	Total Net Output	kW	726,189		
9	DH-Hot Water Supply from CHP, Each Site	Gcal/h	477.3	60.0	0.0
10	DH-Total Hot Water Supply from CHP, All Sites	Gcal/h	537		
11	DH-Hot Water Supply from Boilers, Each Site	Gcal/h	53	120	0
12	DH-Hot Water Supply from Boilers, All Sites	Gcal/h	173		
13	Total DH Hot Water Supply-CHP & Boilers, All Sites	Gcal/h	710		
14	GTG Fuel Input (Each Site)	GJ/h - LHV	2,984.4	399.4	1,514.4
15	HRSG Duct Burner Fuel Input (Each Site)	GJ/h - LHV	1,113.4	93.6	0.0
16	HW Boilers Fuel Input @90% Efficiency, Each Site	GJ/h - LHV	245	558.2	0.0
17	Fuel Gas Consumption-Each Site	GJ/h - LHV	4,343.2	1,051.2	1,514.4
18	Total Fuel Gas Consumption	GJ/h - LHV	6,908.8		
19	Site Cogen Efficiency (LHV) (4)	%	88.96%	87.40%	51.99%
20	Condenser Cooling Load (6)	MWth	16.20	#N/A	144.59
21	Cooling Tower Makeup (7)	t/h	19.83	21.05	#N/A
22	Steam Cycle Makeup (demin water) (8)	t/h	4.19	#N/A	1.22

Item	Description	Units	Option 2		
			Project 2	Project 5	Project 7
B. Plant Performance-Winter Normal DH Load @ 0°C					
1	Number of Operating GTG//Engie		2	5	1
2	GTG/Engine Load	%	100	100	100
3	Number of Operating STG		1	0	1
4	GTG/Engie Output, each	kW	151,908	10,387	154,959
5	STG Output , each	kW	160,005	0	68,438
6	Site Gross Output	kW	463,821	51,935	223,397
7	**Site Net Output**	**kW**	**448,439**	**49,898**	**213,022**
8	**Total Net Output**	**kW**	**711,359**		
9	DH-Hot Water Supply from CHP, Each Site	Gcal/h	380.0	60.0	0.0
10	DH-Total Hot Water Supply from CHP, All Sites	Gcal/h	440		
11	DH-Hot Water Supply from Boilers, Each Site	Gcal/h	0	60	0
12	DH-Hot Water Supply from Boilers, All Sites	Gcal/h	60		
13	Total DH Hot Water Supply-CHP & Boilers, All Sites	Gcal/h	500		
14	GTG Fuel Input (Each Site)	GJ/h - LHV	2,891.9	399.4	1,467
15	HRSG Duct Burner Fuel Input (Each Site)	GJ/h - LHV	849.9	93.6	0
16	HW Boilers Fuel Input @90% Efficiency, Each Site	GJ/h - LHV	0	279	0
17	Fuel Gas Consumption-Each Site	GJ/h - LHV	3,742	772	1,467
18	Total Fuel Gas Consumption	GJ/h - LHV	5,981		
19	Site Cogen Efficiency (LHV) [(4)]	%	85.67%	87.40%	NA
20	Condenser Cooling Load [(6)]	MWth	49.4	#N/A	143.3
21	Cooling Tower Makeup [(7)]	t/h	53.1	22.7	#N/A
22	Steam Cycle Makeup (demin water) [(8)]	t/h	3.75	#N/A	1.20

Item	Description	Units	Option 2		
			Project 2	Project 5	Project 7
C. Plant Performance-Summer Min DH Load @ 25°C					
1	Number of Operating GTG//Engie [(5)]		1	5	1
2	GTG/Engine Load	%	100	100	100
3	Number of Operating STG		1	0	1
4	GTG/Engie Output, each	kW	133,294	10,387	135,904
5	STG Output , each	kW	58,035	0	63,245
6	Site Gross Output	kW	191,329	51,935	199,149
7	**Site Net Output**	**kW**	**182,002**	**49,898**	**189,403**
8	**Total Net Output**	**kW**	**421,303**		
9	DH-Hot Water Supply from CHP, Each Site	Gcal/h	0	60	0
10	DH-Total Hot Water Supply from CHP, All Sites	Gcal/h	60		
11	DH-Hot Water Supply from Boilers, Each Site	Gcal/h	0	0	0
12	DH-Hot Water Supply from Boilers, All Sites	Gcal/h	0		
13	Total DH Hot Water Supply-CHP & Boilers, All Sites	Gcal/h	60.0		
14	GTG Fuel Input (Each Site)	GJ/h - LHV	1,308.6	399.4	1,327.7
15	HRSG Duct Burner Fuel Input (Each Site)	GJ/h - LHV	0.0	93.6	0.0
16	HW Boilers Fuel Input @90% Efficiency, Each Site	GJ/h - LHV	0	0	0
17	Fuel Gas Consumption-Each Site	GJ/h - LHV	1,308.6	493.0	1,327.7
18	Total Fuel Gas Consumption	GJ/h - LHV	3,129		
19	Site Cogen Efficiency (LHV) [(4)]	%	50.07%	87.40%	51.36%
20	Condenser Cooling Load [(6)]	MWth	134.9	#N/A	140.0
21	Cooling Tower Makeup [(7)]	t/h	219.1	27.1	#N/A
22	Steam Cycle Makeup (demin water) [(8)]	t/h	1.05	#N/A	1.19

A summary of the technical analysis for Option 3 is presented in Exhibit 172.

Exhibit 172 Option 3 Technical Analysis Results

Item	Description	Units	Option 3		
			Project 3	Project 5	Project 7
A. Plant Performance-Winter Max DH Load @ -12°C					
1	Number of Operating GTG//Engie		2	5	1
2	GTG/Engine Load	%	100	100	100
3	Number of Operating STG		1	0	1
4	GTG/Engie Output, each	kW	156,645	10,387	159,735
5	STG Output , each	kW	160,314	0	68,700
6	Site Gross Output	kW	473,604	51,935	228,435
7	**Site Net Output**	**kW**	**452,651**	**49,898**	**218,710**
8	Total Net Output	kW	721,259		
9	DH-Hot Water Supply from CHP, Each Site	Gcal/h	482.8	60.0	0.0
10	DH-Total Hot Water Supply from CHP, All Sites	Gcal/h	543		
11	DH-Hot Water Supply from Boilers, Each Site	Gcal/h	47	120	0
12	DH-Hot Water Supply from Boilers, All Sites	Gcal/h	167		
13	Total DH Hot Water Supply-CHP & Boilers, All Sites	Gcal/h	710		
14	GTG Fuel Input (Each Site)	GJ/h - LHV	2,967.2	399.4	1,514.4
15	HRSG Duct Burner Fuel Input (Each Site)	GJ/h - LHV	1,113.1	93.6	0.0
16	HW Boilers Fuel Input @90% Efficiency, Each Site	GJ/h - LHV	220	558.2	0.0
17	Fuel Gas Consumption-Each Site	GJ/h - LHV	4,300.0	1,051.2	1,514.4
18	Total Fuel Gas Consumption	GJ/h - LHV	6,865.6		
19	Site Cogen Efficiency (LHV) (4)	%	89.47%	87.40%	51.99%
20	Condenser Cooling Load (6)	MWth	#N/A	#N/A	144.59
21	Cooling Tower Makeup (7)	t/h	8.1	21.05	#N/A
22	Steam Cycle Makeup (demin water) (8)	t/h	4.12	#N/A	1.22

Item	Description	Units	Option 3		
			Project 3	Project 5	Project 7
B. Plant Performance-Winter Normal DH Load @ 0°C					
1	Number of Operating GTG//Engie		2	5	1
2	GTG/Engine Load	%	100	100	100
3	Number of Operating STG		1	0	1
4	GTG/Engie Output, each	kW	151,936	10,387	154,959
5	STG Output , each	kW	116,997	0	68,438
6	Site Gross Output	kW	420,869	51,935	223,397
7	**Site Net Output**	**kW**	**401,094**	**49,898**	**213,022**
8	**Total Net Output**	**kW**	**664,014**		
9	DH-Hot Water Supply from CHP, Each Site	Gcal/h	380.0	60.0	0.0
10	DH-Total Hot Water Supply from CHP, All Sites	Gcal/h	440		
11	DH-Hot Water Supply from Boilers, Each Site	Gcal/h	0	60	0
12	DH-Hot Water Supply from Boilers, All Sites	Gcal/h	60		
13	Total DH Hot Water Supply-CHP & Boilers, All Sites	Gcal/h	500		
14	GTG Fuel Input (Each Site)	GJ/h - LHV	2,875.0	399.4	1,467
15	HRSG Duct Burner Fuel Input (Each Site)	GJ/h - LHV	613.2	93.6	0
16	HW Boilers Fuel Input @90% Efficiency, Each Site	GJ/h - LHV	0	279	0
17	Fuel Gas Consumption-Each Site	GJ/h - LHV	3,488	772	1,467
18	Total Fuel Gas Consumption	GJ/h - LHV	5,728		
19	Site Cogen Efficiency (LHV) (4)	%	87.01%	87.40%	52.26%
20	Condenser Cooling Load (6)	MWth	#N/A	#N/A	143.3
21	Cooling Tower Makeup (7)	t/h	7.0	22.7	#N/A
22	Steam Cycle Makeup (demin water) (8)	t/h	3.24	#N/A	1.20

Item	Description	Units	Option 3		
			Project 3	Project 5	Project 7
C. Plant Performance-Summer Min DH Load @ 25°C					
1	Number of Operating GTG//Engie (5)		0	5	1
2	GTG/Engine Load	%	0	100	100
3	Number of Operating STG		0	0	1
4	GTG/Engie Output, each	kW	0	10,387	135,904
5	STG Output , each	kW	0	0	63,245
6	Site Gross Output	kW	0	51,935	199,149
7	**Site Net Output**	**kW**	**0**	**49,898**	**189,403**
8	**Total Net Output**	**kW**	**239,301**		
9	DH-Hot Water Supply from CHP, Each Site	Gcal/h	0	60	0
10	DH-Total Hot Water Supply from CHP, All Sites	Gcal/h	60		
11	DH-Hot Water Supply from Boilers, Each Site	Gcal/h	0	0	0
12	DH-Hot Water Supply from Boilers, All Sites	Gcal/h	0		
13	Total DH Hot Water Supply-CHP & Boilers, All Sites	Gcal/h	60.0		
14	GTG Fuel Input (Each Site)	GJ/h - LHV	0.0	399.4	1,327.7
15	HRSG Duct Burner Fuel Input (Each Site)	GJ/h - LHV	0.0	93.6	0.0
16	HW Boilers Fuel Input @90% Efficiency, Each Site	GJ/h - LHV	0	0	0
17	Fuel Gas Consumption-Each Site	GJ/h - LHV	0.0	493.0	1,327.7
18	Total Fuel Gas Consumption	GJ/h - LHV	1,821		
19	Site Cogen Efficiency (LHV) (4)	%	#N/A	87.40%	51.36%
20	Condenser Cooling Load (6)	MWth	#N/A	#N/A	140.0
21	Cooling Tower Makeup (7)	t/h	0.0	27.1	#N/A
22	Steam Cycle Makeup (demin water) (8)	t/h	0.00	#N/A	1.19

A summary of the technical analysis for Option 4 is presented in Exhibit 173.

Exhibit 173 Option 4 Technical Analysis Results

Item	Description	Units	Option 4		
			Project 4	Project 5	Project 7
A. Plant Performance-Winter Max DH Load @ -12°C					
1	Number of Operating GTG//Engie		2	5	1
2	GTG/Engine Load	%	100	100	100
3	Number of Operating STG		1	0	1
4	GTG/Engie Output, each	kW	156,614	10,387	159,735
5	STG Output , each	kW	0	0	68,700
6	Site Gross Output	kW	313,228	51,935	228,435
7	**Site Net Output**	**kW**	**297,938**	**49,898**	**218,710**
8	Total Net Output	kW	566,546		
9	DH-Hot Water Supply from CHP, Each Site	Gcal/h	530.1	60.0	0.0
10	DH-Total Hot Water Supply from CHP, All Sites	Gcal/h	590		
11	DH-Hot Water Supply from Boilers, Each Site	Gcal/h	0	120	0
12	DH-Hot Water Supply from Boilers, All Sites	Gcal/h	120		
13	Total DH Hot Water Supply-CHP & Boilers, All Sites	Gcal/h	710		
14	GTG Fuel Input (Each Site)	GJ/h - LHV	2,966.5	399.4	1,514.4
15	HRSG Duct Burner Fuel Input (Each Site)	GJ/h - LHV	776.4	93.6	0.0
16	HW Boilers Fuel Input @90% Efficiency, Each Site	GJ/h - LHV	0	558.2	0.0
17	Fuel Gas Consumption-Each Site	GJ/h - LHV	3,742.9	1,051.2	1,514.4
18	Total Fuel Gas Consumption	GJ/h - LHV	6,308.6		
19	Site Cogen Efficiency (LHV) (4)	%	87.95%	87.40%	51.99%
20	Condenser Cooling Load (6)	MWth	#N/A	#N/A	144.59
21	Cooling Tower Makeup (7)	t/h	6.7	21.05	#N/A
22	Steam Cycle Makeup (demin water) (8)	t/h	4.55	#N/A	1.22

Item	Description	Units	Option 4		
			Project 4	Project 5	Project 7
B. Plant Performance-Winter Normal DH Load @ 0°C					
1	Number of Operating GTG//Engie		2	5	1
2	GTG/Engine Load	%	100	100	100
3	Number of Operating STG		1	0	1
4	GTG/Engie Output, each	kW	152,109	10,387	154,959
5	STG Output , each	kW	0	0	68,438
6	Site Gross Output	kW	304,218	51,935	223,397
7	**Site Net Output**	**kW**	**289,353**	**49,898**	**213,022**
8	**Total Net Output**	**kW**	**552,273**		
9	DH-Hot Water Supply from CHP, Each Site	Gcal/h	380.0	60.0	0.0
10	DH-Total Hot Water Supply from CHP, All Sites	Gcal/h	440		
11	DH-Hot Water Supply from Boilers, Each Site	Gcal/h	0	60	0
12	DH-Hot Water Supply from Boilers, All Sites	Gcal/h	60		
13	Total DH Hot Water Supply-CHP & Boilers, All Sites	Gcal/h	500		
14	GTG Fuel Input (Each Site)	GJ/h - LHV	2,875.6	399.4	1,467
15	HRSG Duct Burner Fuel Input (Each Site)	GJ/h - LHV	172.4	93.6	0
16	HW Boilers Fuel Input @90% Efficiency, Each Site	GJ/h - LHV	0	279	0
17	Fuel Gas Consumption-Each Site	GJ/h - LHV	3,048	772	1,467
18	Total Fuel Gas Consumption	GJ/h - LHV	5,288		
19	Site Cogen Efficiency (LHV) [4]	%	86.38%	87.40%	52.26%
20	Condenser Cooling Load [6]	MWth	#N/A	#N/A	143.3
21	Cooling Tower Makeup [7]	t/h	6.5	22.7	#N/A
22	Steam Cycle Makeup (demin water) [8]	t/h	3.24	#N/A	1.20

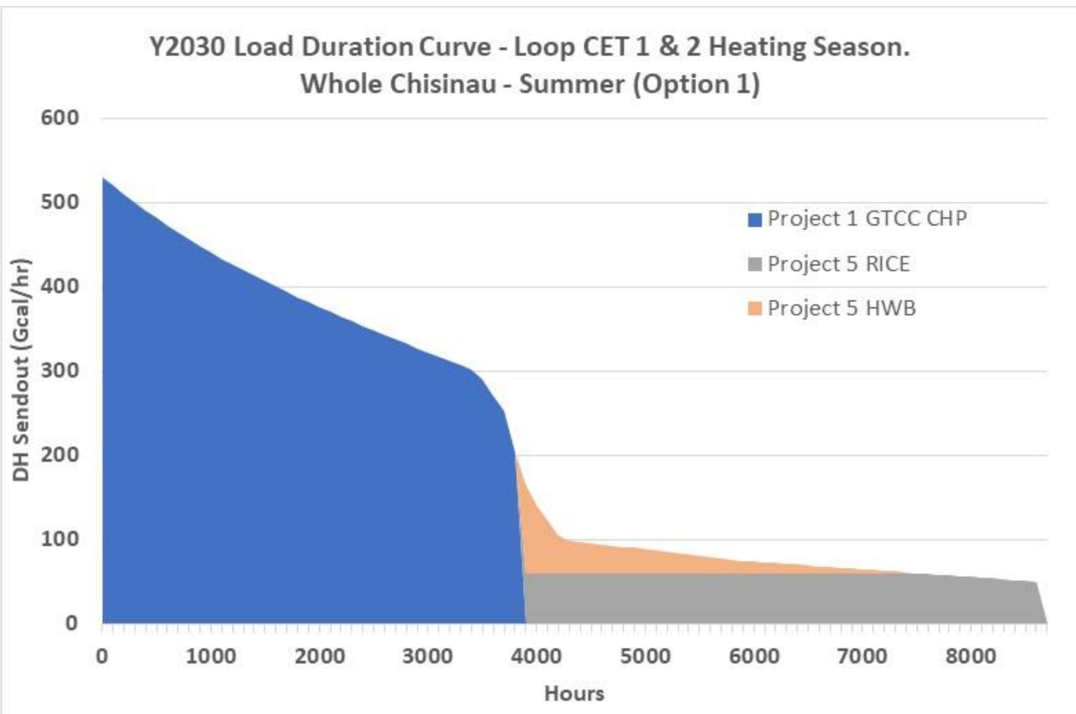
Item	Description	Units	Option 4		
			Project 4	Project 5	Project 7
C. Plant Performance-Summer Min DH Load @ 25°C					
1	Number of Operating GTG//Engie [5]		0	5	1
2	GTG/Engine Load	%	0	100	100
3	Number of Operating STG		0	0	1
4	GTG/Engie Output, each	kW	0	10,387	135,904
5	STG Output , each	kW	0	0	63,245
6	Site Gross Output	kW	0	51,935	199,149
7	**Site Net Output**	**kW**	**0**	**49,898**	**189,403**
8	**Total Net Output**	**kW**	**239,301**		
9	DH-Hot Water Supply from CHP, Each Site	Gcal/h	0	60	0
10	DH-Total Hot Water Supply from CHP, All Sites	Gcal/h	60		
11	DH-Hot Water Supply from Boilers, Each Site	Gcal/h	0	0	0
12	DH-Hot Water Supply from Boilers, All Sites	Gcal/h	0		
13	Total DH Hot Water Supply-CHP & Boilers, All Sites	Gcal/h	60.0		
14	GTG Fuel Input (Each Site)	GJ/h - LHV	0.0	399.4	1,327.7
15	HRSG Duct Burner Fuel Input (Each Site)	GJ/h - LHV	0.0	93.6	0.0
16	HW Boilers Fuel Input @90% Efficiency, Each Site	GJ/h - LHV	0	0	0
17	Fuel Gas Consumption-Each Site	GJ/h - LHV	0.0	493.0	1,327.7
18	Total Fuel Gas Consumption	GJ/h - LHV	1,821		
19	Site Cogen Efficiency (LHV) [4]	%	#N/A	87.40%	51.36%
20	Condenser Cooling Load [6]	MWth	#N/A	#N/A	140.0
21	Cooling Tower Makeup [7]	t/h	0.0	27.1	#N/A
22	Steam Cycle Makeup (demin water) [8]	t/h	0.00	#N/A	1.19

8.2.3 DISTRICT HEATING PERFORMANCE RESULTS

District heating demand can be characterized by the peak heat load and the annual heat production. The peak demand (Gcal/h) is important for the sizing of the district heating sources and the supply network system. Annual district heating production (Gcal/y) determines the heat revenues and the fuel consumption requirement. A load duration curve relates both of these items in a single curve. The peak demand is the highest point on the curve, while annual heat production is the area underneath the curve. During the heating season, the heat demand of the Chisinau CET-1/CET-2 loop is satisfied by the new CHP units (Projects 1, 2, 3 and 4), with the balance of heat where applicable provided by the existing Hot Water Boilers. During the off-heating season period, hot water service for all the Chisinau district heating system is provided by the new RICE units (Project 5) and the existing Hot Water Boilers located at the CT VEST and CT SUD sites.

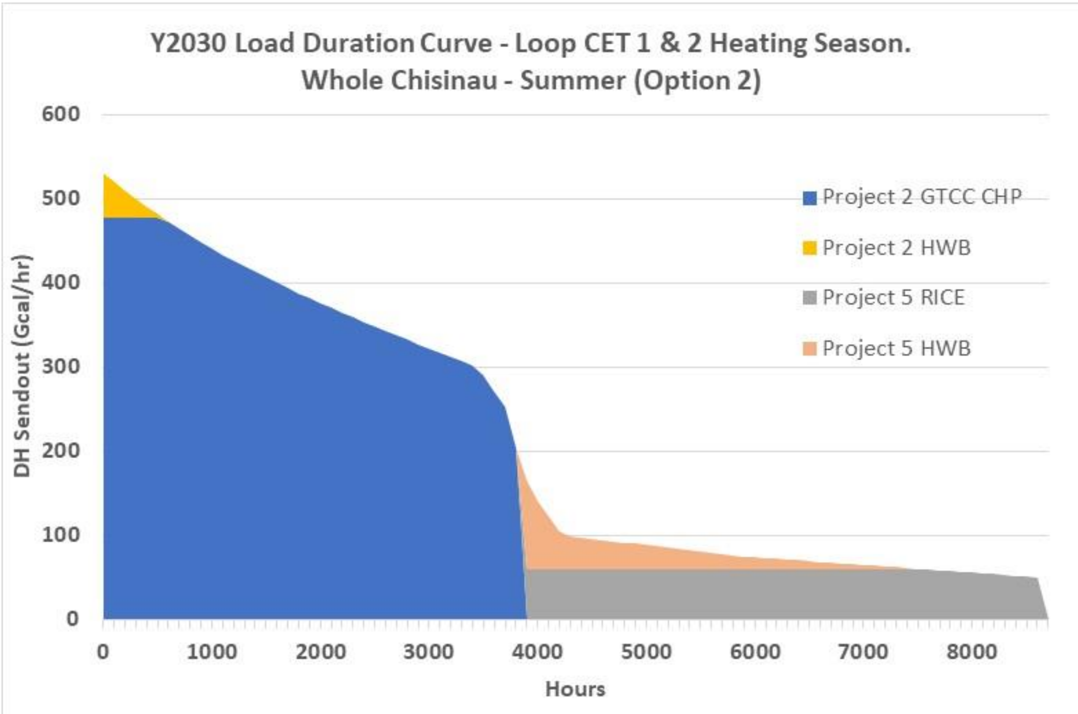
The annual dispatch order of the Project 1 plant to meet the district heating demand in 2030 is illustrated in Exhibit 174.

Exhibit 174 DH Dispatch Order for Project 1 in 2030



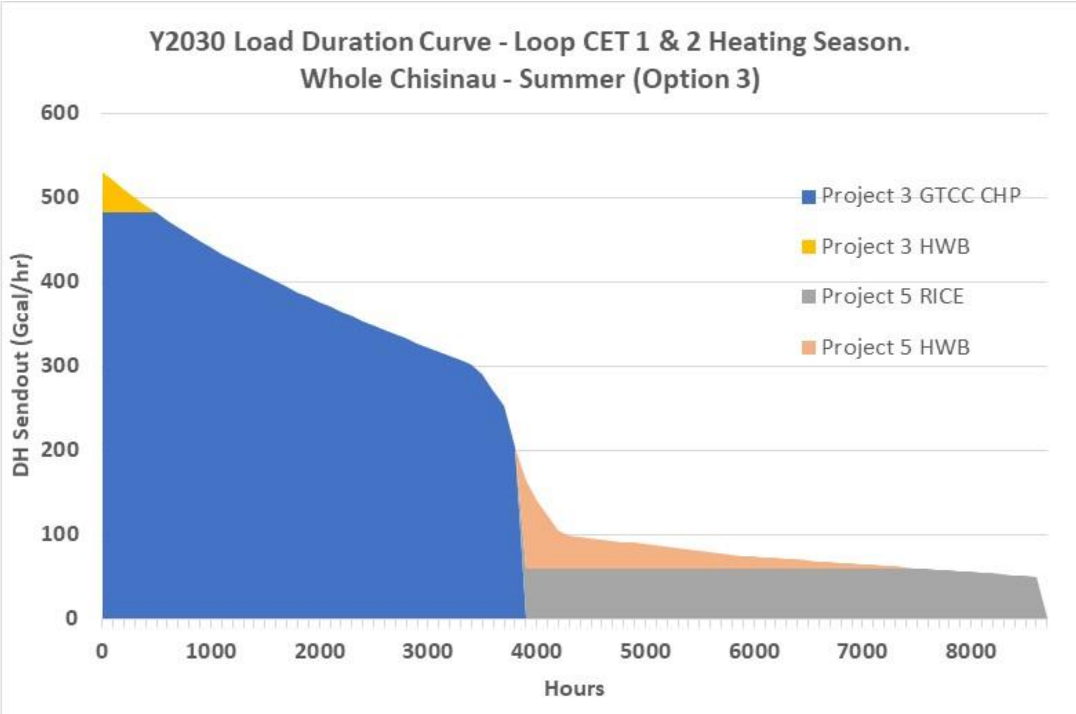
The annual dispatch order of the Project 2 plant to meet the district heating demand in 2030 is presented in Exhibit 175.

Exhibit 175 DH Dispatch Order for Project 2 in 2030



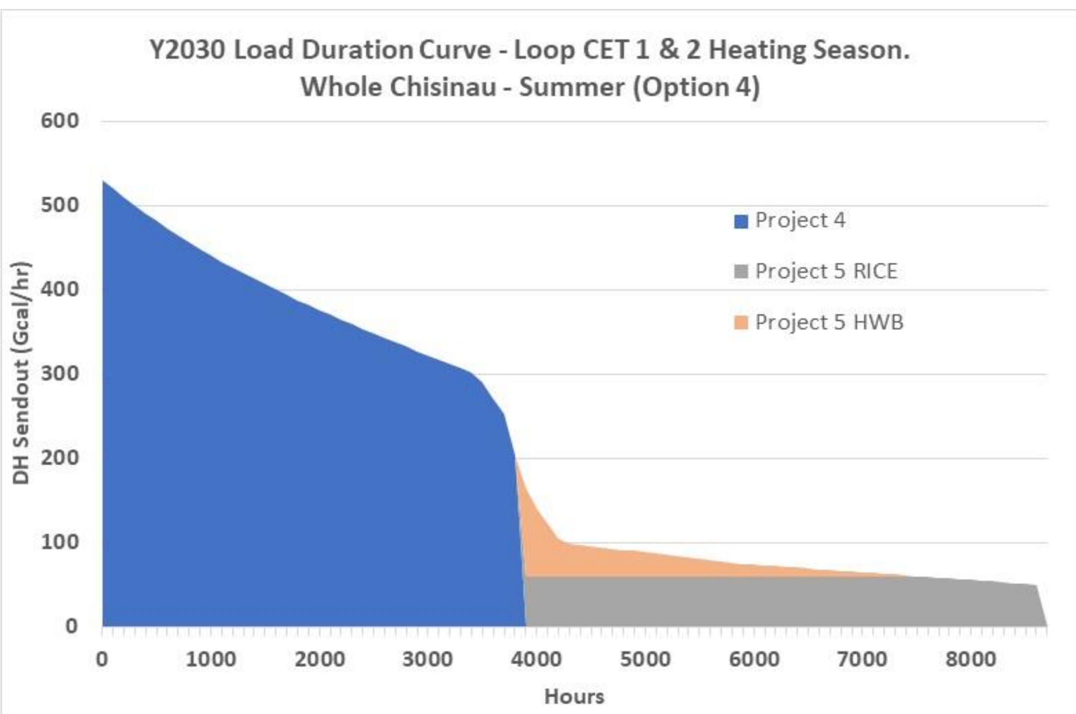
The annual dispatch order of the Project 3 plant to meet the district heating demand in 2030 is presented in Exhibit 176.

Exhibit 176 DH Dispatch Order for Project 3 in 2030



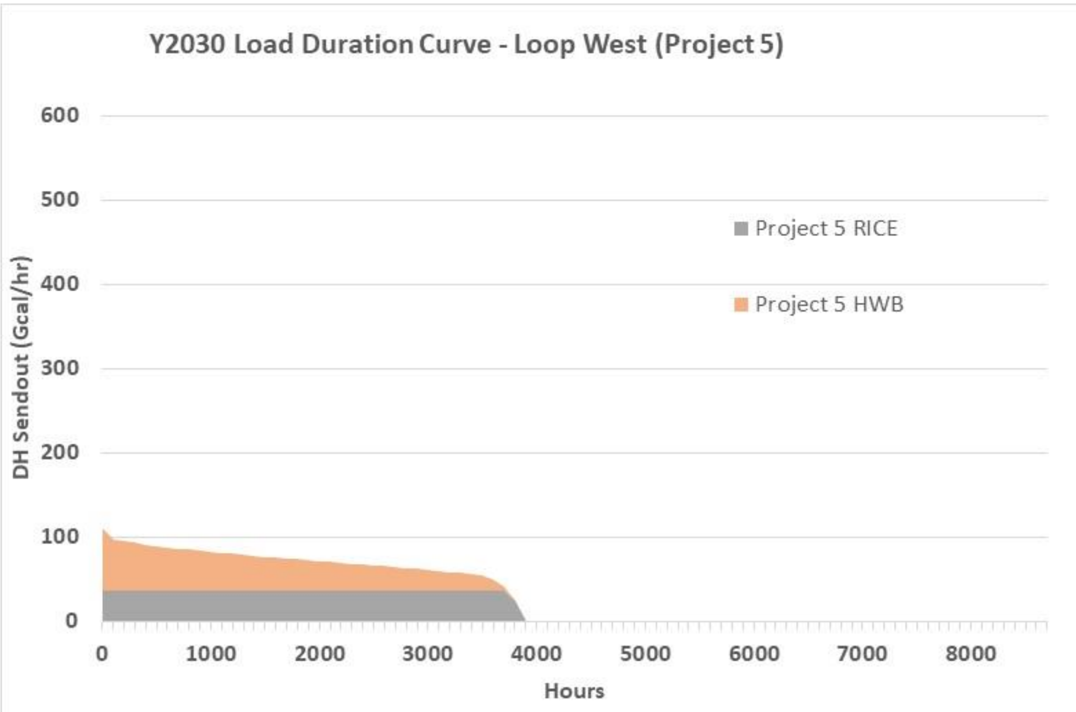
The annual dispatch order of the Project 4 plant to meet the district heating demand in 2030 is presented in Exhibit 177.

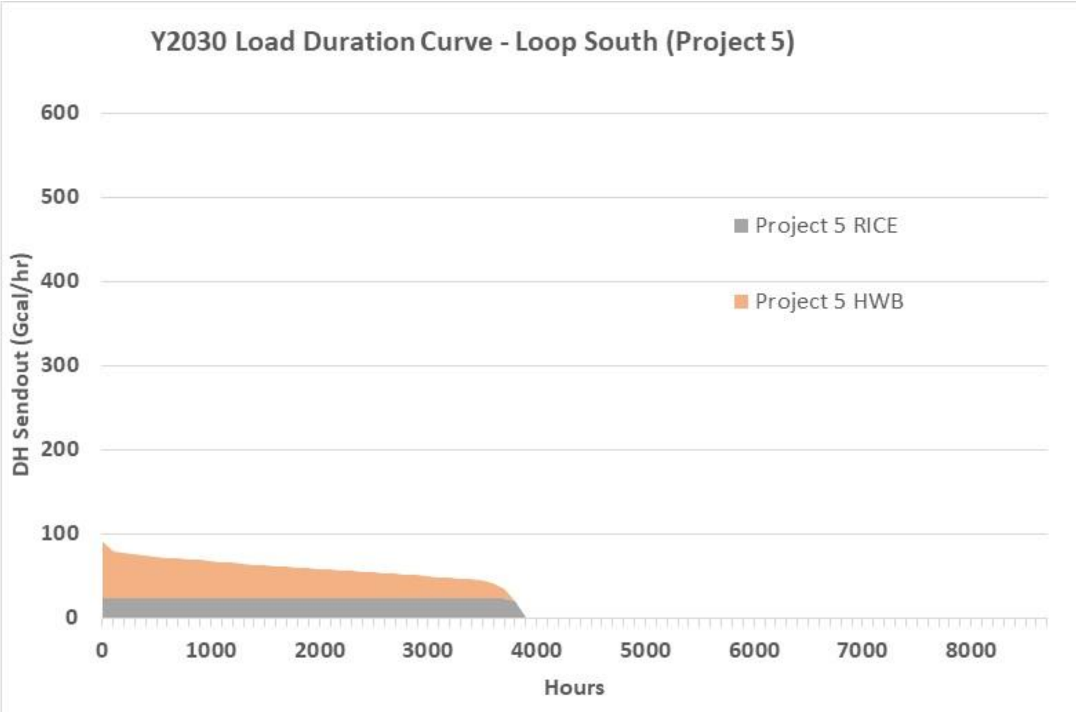
Exhibit 177 DH Dispatch Order for Project 4 in 2030



Project 5 plants are included in all four options. During the heating season Project 5 plants provide heating service to their dedicated VEST and SUD DH loops, with the three new RICE units installed at CT VEST plant and two new RICE units at the CT SUD plant. The annual dispatch order for the Project 5 VEST and SUD units to meet their respective district heating demand in 2030 is presented Exhibit 178. The dispatch order shows a portion of heat demand satisfied by the new RICE units, with the balance of the heat demand supplied by the existing hot water boilers.

Exhibit 178 DH Dispatch Order for Project 5 in 2030





The estimated annual heat production by each project is summarized in Exhibit 179.

Exhibit 179 Annual Heat Production

Options	Heat production, 1000 Gcal / year							
	Project 1	Project 2	Project 3	Project 4	Project 5	Project 6	Project 7	Total
Option 1	1,474				766			**2,240**
Option 2		1,474			766			**2,240**
Option 3			1,474		766			**2,240**
Option 4				1,474	766			**2,240**

The estimated annual electric power generation by each project is presented in Exhibit 180.

Exhibit 180 Annual Electric Power Generation

Options	Electric Power Generation, 1000 MWh / year							
	Project 1	**Project 2**	**Project 3**	**Project 4**	**Project 5**	**Project 6**	**Project 7**	**Total**
Option 1	2800				437	946		**4,183**
Option 2		2,609			437		1,313	**4,359**
Option 3			1,535		437		1,313	**3,285**
Option 4				1,101	437		1,313	**2,851**

The overall fuel utilization efficiency (Exhibit 181) is defined as: (net plant electric output + all useful heat output) / (Total fuel LHV input). It includes thermal energy and fuel consumption from hot water boilers.

Exhibit 181 Overall Fuel Utilization Efficiency

	Option 1	**Option 2**	**Option 3**	**Option 4**
Overall Fuel Utilization Efficiency	70.8%	70.8%	75.8%	74.7%

8.3 CAPITAL EXPENDITURES

Capital expenditures (CAPEX) have been developed utilizing Thermoflow Plant Engineering and Construction Estimator (PEACE) software. PEACE is extensively used in the industry for relative pricing comparison of options and screening analysis. CAPEX estimates performed by PEACE are based on the same underlying assumptions for all the projects, and therefore, all the options are compared on a level playing field. Any changes in the assumptions will impact CAPEX for all the projects in similar fashion. As such, these CAPEX are not investment cost estimates, and should only be considered for the relative comparison purposes. CAPEX summaries for each project and option are presented in Exhibit 182.

Exhibit 182 CAPEX Summary

Description	Units	Option 1		
		Project 1	Project 5	Project 6
EPC Cost	x1000 US$	406,900	48,800	164,100
Owner's development and allowance	x1000 US$	36,600	4,400	14,800
Owner's Total Cost per Project	x1000 US$	443,500	53,100	178,900
Total Costs per Option	**x1000 US$**	**675,500**		
Description	**Units**	**Option 2**		
		Project 2	**Project 5**	**Project 7**
EPC Cost	x1000 US$	367,900	48,800	189,700
Owner's development and allowance	x1000 US$	33,100	4,400	17,100
Owner's Total Cost per Project	x1000 US$	401,000	53,100	206,800
Total Costs per Option	**x1000 US$**	**660,900**		
Description	**Units**	**Option 3**		
		Project 3	**Project 5**	**Project 7**
EPC Cost	x1000 US$	333,500	48,800	189,700
Owner's development and allowance	x1000 US$	30,000	4,400	17,100
Owner's Total Cost per Project	x1000 US$	363,500	53,100	206,800
Total Costs per Option	**x1000 US$**	**623,400**		
Description	**Units**	**Option 4**		
		Project 4	**Project 5**	**Project 7**
EPC Cost	x1000 US$	231,500	48,800	189,700
Owner's development and allowance	x1000 US$	20,800	4,400	17,100
Owner's Total Cost per Project	x1000 US$	252,400	53,100	206,800
Total Costs per Option	**x1000 US$**	**512,300**		

8.4 ECONOMIC ANALYSIS AND PROJECT SELECTION

8.4.1 GENERAL ECONOMIC ASSUMPTIONS

The general economic analysis assumptions for the four (4) considered options are presented in the following subsections.

APPROACH

As discussed earlier, the project is expected to reach financial closure in the first half of 2026 and start construction in the second half of the same year. Then, the project is expected to achieve commercial operation at the beginning of 2030.

For the purposes of this comparative economic assessment, to avoid uncertainties related to forecasting future price escalation of plant equipment, materials, labor, commodities (gas, electricity, heat), etc., the options are compared based on an assumption that the construction of all projects will start now, and the projects will be in commercial operation at end of the construction period.

This approach is reasonable as Capital Expenditures (CAPEX) and Operating Expenditures (OPEX) are available in 2019 prices, and there will be no need to predict their escalation through 2026. Furthermore, today's commodity prices are assumed in the first year of project operation.

TIMEFRAME

The duration of project construction is assumed to be 40 months and is equal for all options.

The Design Life of all options is assumed to be 30 years after the start of operation.

All cost inputs are assumed at the end of 2019 / beginning of 2020, and all future values are discounted to the beginning of 2020.

CAPITAL COSTS

Capital costs for all projects are provided in Exhibit 182. They are equally distributed through the months of construction. The Engineer Procure Construct (EPC) price is assumed to be firm and fixed, i.e. no escalation during construction is applied on the EPC prices.

The same approach is applied to the Owner's costs.

ELECTRICITY AND HEAT PRODUCTION

Electricity and heat production are as estimated in Exhibit 179 and Exhibit 180.

The capacity factor for Projects 6 and 7 for the Base case is assumed at 75%.

CURRENCY

All values are presented in 2019 USD.

MAINTENANCE AND OPERATING COSTS

Maintenance and Operating (O&M) costs are applied as per the Exhibit 183.

Exhibit 183 Maintenance and Operating Costs

Project	Prime mover	Fixed O&M Cost per RiCE/ GT, $M (Note 1)	Total Fixed O&M Cost $M (Note) 2	STG CAPEX, $M	STG OPEX $M/y	Major STG Overhaul $M
1	3 x GT1	0.35M/Y+$6.5M major overhaul every 8-10 yrs	$1.05M/Y +$19.5M major overhaul every 8 yrs	$21.3	3%, at $0.64M/y	25% every 16 yrs, at $5.33 M
2	2 x GT2	$0.5M/Y+$8M major overhaul for every 8-10 yrs	$1.0M/Y +$16 M major overhaul every 8 yrs	$21.1	3%, at $0.63M/y	25% every 16 yrs, at $5.28 M
3	2 x GT2	$0.5M/Y+$8M major overhaul for every 8-10 yrs	$1.0M/Y +$16 M major overhaul every 8 yrs	$19.0	3%, at $0.57M/y	20% every 16 yrs at $3.80 M
4	2 x GT2	$0.5M/Y+$8M major overhaul for every 8-10 yrs	$1.0M/Y +$16 M major overhaul every 8 yrs	NA	NA	NA
5	5 x RICE	$0.1M/Y+ $1M major overhaul for every 5 yrs	$0.5M/Y +$5 M major overhaul every 5 yrs	NA	NA	NA
6	1 x GT1	0.35M/Y+$6.5M major overhaul for every 8-10 yrs	0.35M/Y +$6.5M major overhaul every 8 yrs	$11.6	3%, at $0.35M/y	25% every 16 yrs at $2.9 M
7	1 x GT2	$0.5M/Y +$8M major overhaul for every 8-10 yrs	$0.5M/Y +$8M major overhaul every 8 yrs	$13.0	3%, at $0.39M/y	25% every 16 yrs at $3.25 M

Notes:

1. Fixed O&M costs include Fixed Long Term Service Agreement (LTSA) fee and major overhaul Costs on a per RICE/GT basis
2. Total Fixed O&M Costs do not include STG O&M costs
3. NA – Not applicable

In addition to the O&M costs presented in Exhibit 183, OPEX include labor costs of the operational personnel and cost of water.

LABOR COSTS

The number of personnel assigned per project is assumed as presented in Exhibit 184.

Exhibit 184 Operating Personnel

	Project 1	Project 2	Project 3	Project 4	Project 5	Project 6	Project 7
Number of Personnel	45	45	44	39	30	44	44

The total labor cost per person is estimated at 1500 USD/month, including 23% social tax payable by the employer.

COST OF WATER

The cost of water has been calculated for each project with the cost of raw make-up water at 0.45 USD/t, and demineralized water at 1.2 USD/t.

OPEX ESCALATION

OPEX is escalated at 0.2 % per year, except for the labor costs which are escalated at 0.5% per year.

FUEL COSTS AND CHP ALLOCATION

Gas consumption of the CHP's has been divided between electricity and heat production using the draft fuel allocation formula from the new ANRE methodology [75].

In case of energy production at urban CHPs, considering that cogeneration represents simultaneous production, within the same process, of electricity and heat within the same facility/plant, the present Methodology allocates the used fuel cost between the produced electricity and heat, so that the fuel saving, compared to separate production of electricity and heat, is distributed in a non-discriminatory manner between the two forms of energy produced simultaneously.

The fuel saving is determined according to the formula:

$$\Delta \boldsymbol{Q_{CHPj}} = \left(Q_{TPPj} + Q_{HOBj}\right) - Q_{CHPj} = \left(\frac{E_j}{\eta_{TPP}} + \frac{H_j}{\eta_{HOB}}\right) - \frac{E_j + H_j}{\eta_{CHPj}} \quad (1)$$

where:

ΔQ_{CHPj} – fuel saving, GJ;

Q_{TPPj} – amount of fuel needed for separate production of the amount of electricity Ej at an efficient (condensation) thermal power plant (TPP), GJ;

Q_{HOBj} – amount of fuel needed for separate production of the amount of heat Hj at a heat-only boiler plant (HOB), GJ;

$\boldsymbol{\eta_{HOB}}$– reference efficiency of the most efficient heat-only boiler plant in the country (with capacity comparable to heat capacity of CHP). According to the present methodology $\boldsymbol{\eta_{HOB}}$=0.92;

Q_{CHPj} – amount of fuel used by the CHP in the year, j" for simultaneous production of the amount of electricity Ej and heat Hj;

Ej – amount of electricity produced by the CHP in the year, j", GJ;

Hj – amount of heat produced by the CHP in the year, j", GJ;

$\boldsymbol{\eta_{TPP}}$– reference efficiency of an efficient (condensation) steam-turbine thermal power plant (without combined cycle). According to the present methodology η_{TPP}=0.35;

$\boldsymbol{\eta_{CHPj}}$ – global (total) electricity and heat production efficiency of the CHP in the year j

Amount of fuel allocated to the electricity produced at the CHP is determined according to the formula:

$$\boldsymbol{Q_{Ej}} = Q_{TPPj} - \Delta Q_{CHPj} \mathrm{X} \left(\frac{Q_{TPPj}}{Q_{TTPj} + Q_{HOBj}}\right) \quad (2)$$

Amount of fuel allocated to the heat produced at the CHP is determined according to the formula:

$$\boldsymbol{Q_{Hj}} = Q_{HOBj} - \Delta Q_{CHPj} \mathrm{X} \left(\frac{Q_{HOBj}}{Q_{TTPj} + Q_{HOBj}}\right) \quad (3)$$

Gas consumption is converted to 1000 m^3 at LHV of 34.2 MJ/m^3 (8184 $Kcal/m^3$), an average value reported by Moldtransgas.

FINANCING

Project financing is assumed as presented in Exhibit 185.

Exhibit 185 Project Financing Assumptions

Financial Parameters	Value
Equity / Debt ratio	25% / 75%
Interest on credit (all-in): • During construction • During repayment	 5% 4.5%
Grace period for the principal	40 months
Repayment period	15 years
Discount rate (Base case)	5%

TAXATION / DEPRECIATION

Assets are split into Buildings, Equipment and short-life, with depreciation periods of 30, 25 and 10 years respectively. Linear amortization is applied.

A corporate income tax rate of 12% is applied in positive incomes before taxes.

COMMODITY PRICE FORECAST ASSUMPTIONS (DH, ELECTRICITY, FUEL)

The assumed commodity pricing and escalation are presented in Exhibit 186

Exhibit 186 Commodity Prices

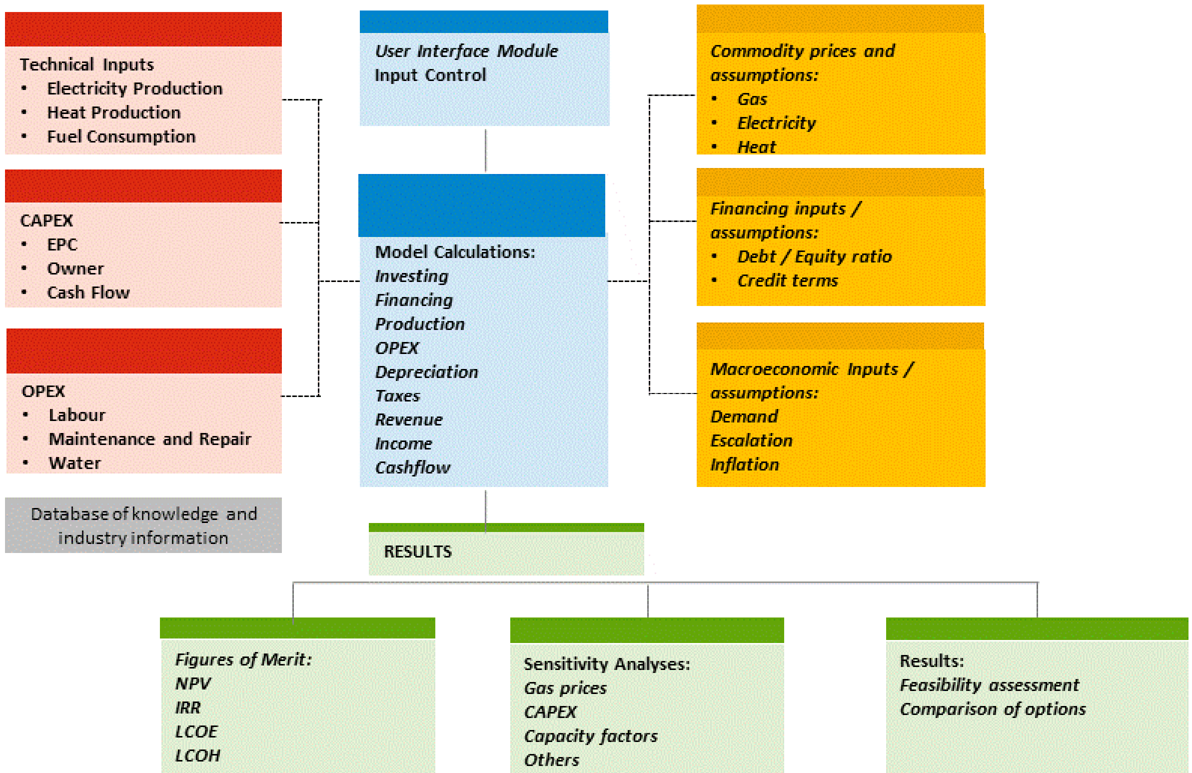
Commodity	Price	Escalation
Natural Gas	240 USD/1000 m^3	0.35% per year
Electricity	65 USD/MWh	0.2% per year
Heat	30 USD/Gcal	0.2% per year

8.4.2 ECONOMIC ANALYSIS

MODEL

Economic analyses are performed utilizing a financial model, which is structured as presented in Exhibit 187.

Exhibit 187 Financial Model Structure



FIGURES OF MERIT

The following figures of merit are calculated as a result of the economic analysis modeling:

NPV represents the value of future cash flows today (or at the base discounting year). This value is calculated by applying the required discount rate (typically the industry discount rate, the firm's cost of capital, or the required rate of return). The positive NPV is an indicator of the project's feasibility. NPV is calculated at 5% discount for the Base Case.

IRR – internal rate of return. IRR is the discount factor at which net present value of the project equals to zero, or at which NPV of negative cash flow equals the NPV of positive cash flow of the project. The IRR is usually compared with the expected rate of return from the project and is an indicator of the efficiency, quality and yield of project investments. IRR will be calculated at net project cash flow, which will consider equity investments, debt repayments, revenue, operational costs, taxes, etc.

LCOE is represented by the cost at which the present value of all revenues from electricity generation is equal to the present value of all expenditures for its production (including construction and operation). LCOE is calculated for the whole lifetime of the project, and represents NPV of expenses divided to NPV of production, or by applying the formula:

$$LCOE = \frac{\sum_{i=1}^{N} \frac{(Annual\ Cost)_i}{(1+d)^{t_i}}}{\sum_{i=1}^{N} \frac{(Annual\ production)_i}{(1+d)^{t_i}}}$$

Where d is the discount factor.

LCOH is calculated in the same way as the LCOE but considering the expenses and amount of the heat production.

Distribution of fuel costs to electricity and heat is made applying the methodology described above. CAPEX and OPEX are split between the products applying the same % distribution as calculated for the fuel.

8.4.3 BASE CASE RESULTS

The Base Case analysis is formed based on the input data and assumptions presented above regarding the commodity prices, capital costs, electricity production, discount factor. The Base Case parameters are summarized below. Sensitivity analyses are performed for the changes in these input parameters.

Exhibit 188 Base Case Economic Parameters

Parameter	Values for the Base Case
Natural Gas Price, year 1	240 USD/1000 m^3
Electricity Price, year 1	65 USD/MWh
Heat Price, year 1	30 USD/Gcal
Capacity factor for Projects 6 and 7	75%
Capital Costs	As per Exhibit 182
Discount Factor	5%

The results of the economic analysis are provided in Exhibit 189.

Exhibit 189 Economic Analysis Results

Option		**1**	**2**	**3**	**4**
NPV	mln. USD	$370	**$439**	$295	$217
IRR	%	13.04%	**14.55%**	12.00%	11.38%
LCOE	USD/MWh	60.18	**59.12**	60.07	61.14
LCOH	USD/Gcal	26.62	**26.36**	27.36	28.13
LCOE breakdown					
Fuel		82%	83%	80%	82%
Capex		15%	14%	16%	15%
Opex		3%	3%	4%	3%
LCOH breakdown					
Fuel		82%	83%	80%	82%
Capex		15%	14%	16%	15%
Opex		3%	3%	4%	3%

Option 2 is the favored option based on all four (4) economic evaluation criteria (NPV, IRR, LCOE, and LCOH). A sensitivity analysis allows for the examination of the robustness of the Base case ranking considering variability of economic input assumptions.

8.4.4 SENSITIVITY ANALYSES

Sensitivity analyses have been performed for the range of economic input parameters presented in Exhibit 190.

Exhibit 190 Economic Sensitivity Matrix

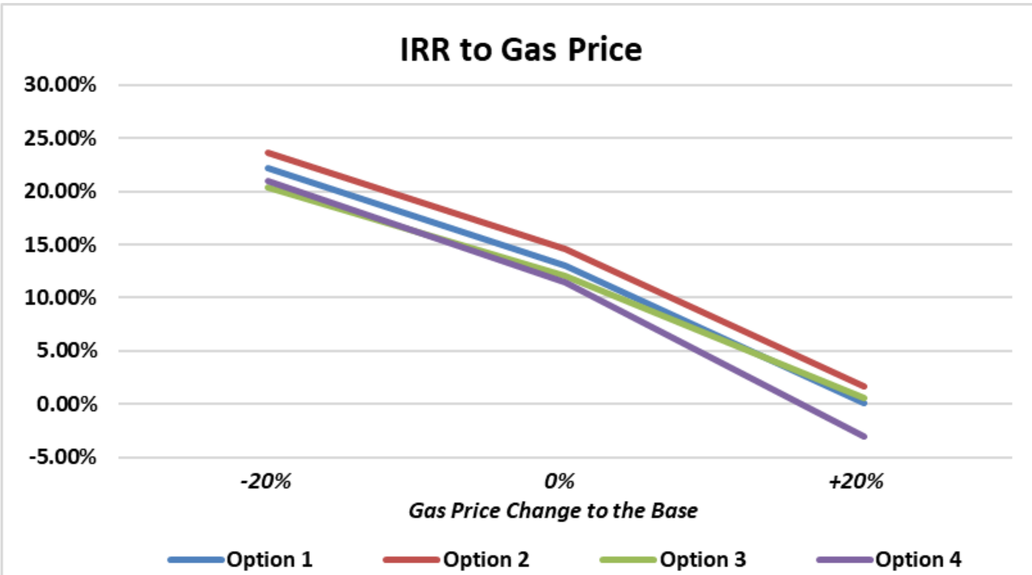
Parameter	**Value for the Base Case**	**Sensitivity**
Natural Gas Price, year 1	240 USD/1000 m^3	+/- 20%
Electricity Price, year 1	65 USD/MWh	+/- 20%
Heat Price, year 1	30 USD/Gcal	+/- 20%
Capacity factor for Projects 6 and 7	75%	65% 95%
Capital Costs	As per Exhibit 17	+/- 20%
Discount Factor	5%	0%, 2.5%, 7.5%, 10%

SENSITIVITY ANALYSIS FOR IRR

The results of the sensitivity analyses are presented as charts below. The first set of figures present the sensitivity of IRR to the change of input parameters. The two most sensitive economic inputs (creating the most significant change to the project IRR) are the gas price and electricity price.

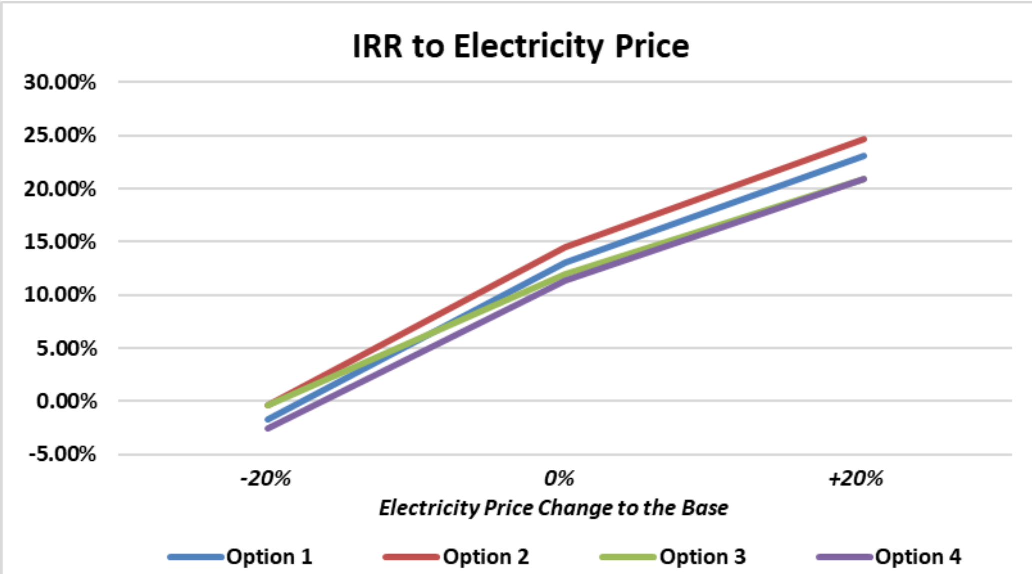
Option 2 has the highest IRR over the analyzed gas price sensitivity range. Option 1 is the next highest option from about -20% to +15% in gas pricing. At about +15% in gas price, Option 3 becomes competitive with Option 2.

Exhibit 191 IRR Sensitivity to Gas Price



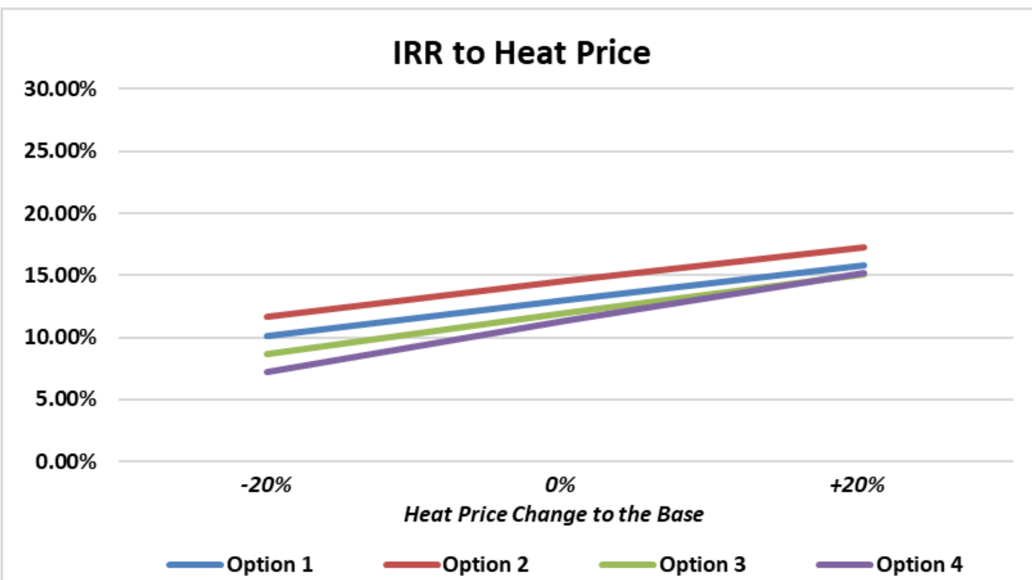
Option 2 has the highest IRR over the analyzed electricity price sensitivity range. Option 1 is the next highest option between about -10% and +20% electricity pricing. Below about -10% electricity pricing Option 3 rises above Option 1, until it becomes competitive with Option 2 near the -20% electricity pricing.

Exhibit 192 IRR Sensitivity to Electricity Price



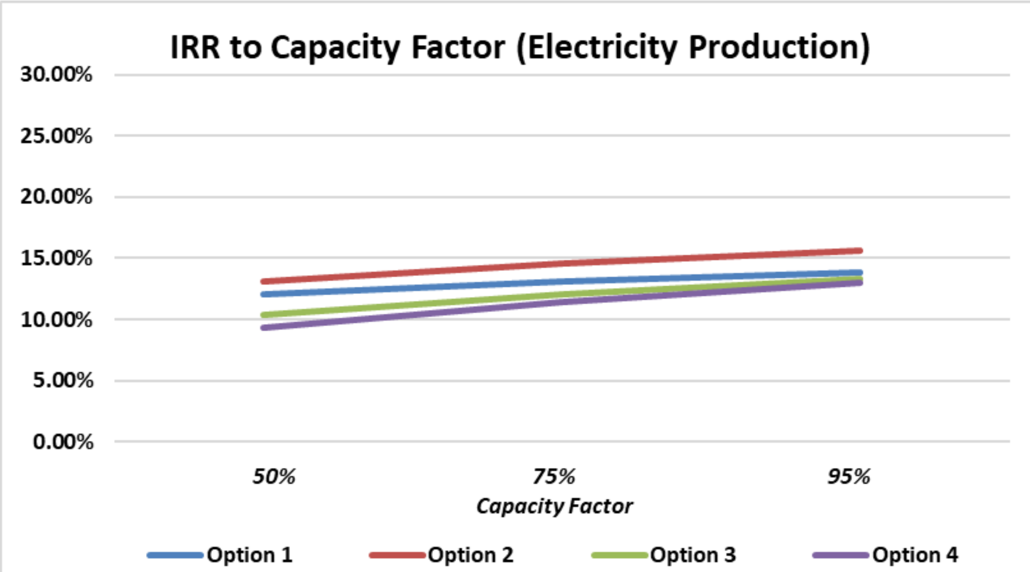
The sensitivity of the IRR to the heat pricing is much less significant than to the gas and electricity pricing. Option 2 has the highest IRR over the analyzed heat price sensitivity range. Option 1 has the second highest IRR. The analyzed range of heat pricing does not show any reranking of the options from the rank order of Option 2, 1, 3 and 4.

Exhibit 193 IRR Sensitivity to Heat Price



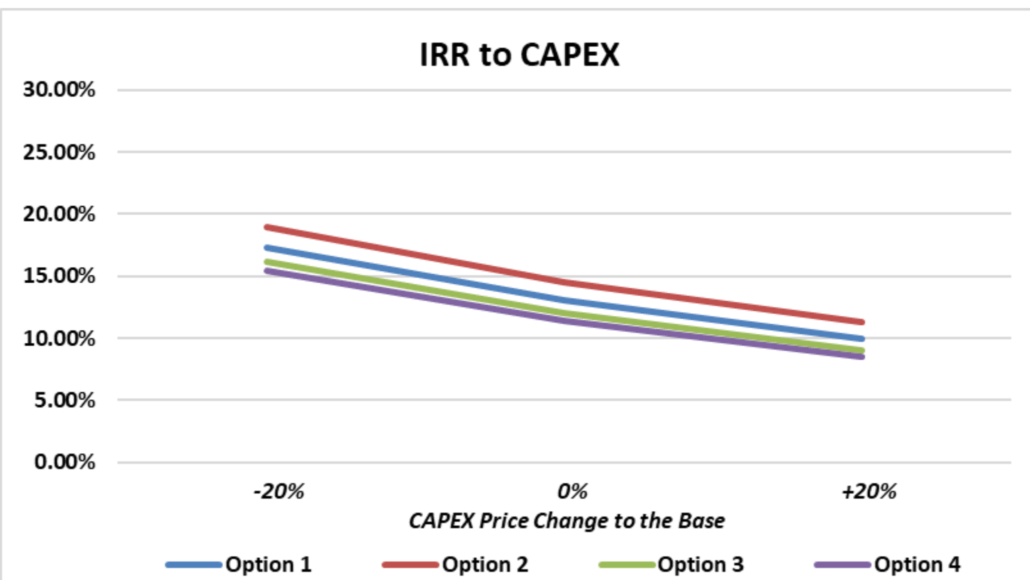
The sensitivity of the IRR to the capacity factor of Project 6 and 7 is also much less significant than to the gas and electricity pricing, and even less so than the heat pricing. Option 2 has the highest IRR over the analyzed heat price sensitivity range. Option 1 has the second highest IRR. The analyzed range of capacity factor range does not show any reranking of the options from the rank order of Option 2, 1, 3 and 4.

Exhibit 194 IRR Sensitivity to Project 6 & & Capacity Factor



The sensitivity of the IRR to the capital expenditures is roughly 1/3 as significant as that of the gas and electricity pricing. Option 2 has the highest IRR over the analyzed capex sensitivity range. Option 1 has the second highest IRR over the entire analyzed capex range. The analyzed range of capex does not show any reranking of the options from the rank order of Option 2, 1, 3 and 4.

Exhibit 195 IRR Sensitivity to Capital Expenditures



The IRR is most sensitive to the natural gas price. Should the gas price be changed, an adjustment of electricity and heat prices would also needed (and expected) in order to keep the project profitable.

The IRR is sensitive also to the selling price of products (electricity and heat), where the impact of changes to the electricity prices is higher than that of heat.

The sensitivity of IRR to changes in the capital costs is also important, however due to the lower share of capital costs in the cost of the products (electricity and heat), the influence of capital costs is much lower than those of fuel price and selling price of electricity.

Option 2 shows to be the most promising option from economic evaluation and sensitivity analysis perspective. However, further analysis might be needed to assess the risks of this option, in terms of (i) the availability of a market for the electricity at high capacity factors (75% or more) (ii) loss of 2 generators totaling more than 160 MWe with a single failure.

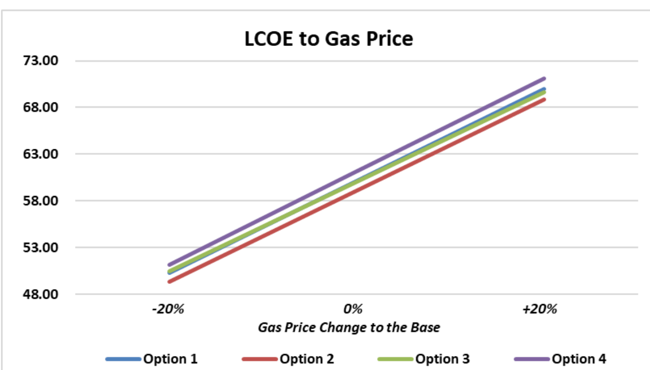
Option 1 is close to Option 2 from the IRR perspective, and might show to be an optimal solution if the aforementioned risks of Option 2 are considered.

An interesting result is obtained for Option 3, whose IRR is less sensitive to gas and electricity prices and the option shows better results than Option 1 in the pessimistic cases of high gas prices or low electricity prices. This result is explained by the lower share of fuel in the levelized cost of products for this option, which is due to the higher total efficiency of this option comparing to the other options (Project 3 has higher efficiency comparing to Projects 1, 2 and 4).

SENSITIVITY ANALYSIS FOR LCOE AND LCOH

Additional sensitivity analyses were developed for the figure-of-merit of LCOE and LCOH instead of the IRR. These Figures are presented below and follow very similar trends as the sensitivities to IRR. Option 2 is again the best option over the analyzed sensitivity ranges. Additional remarks are presented below the LCOE and LCOH exhibits.

Exhibit 196 LCOE & LCOH Sensitivity to Gas Price



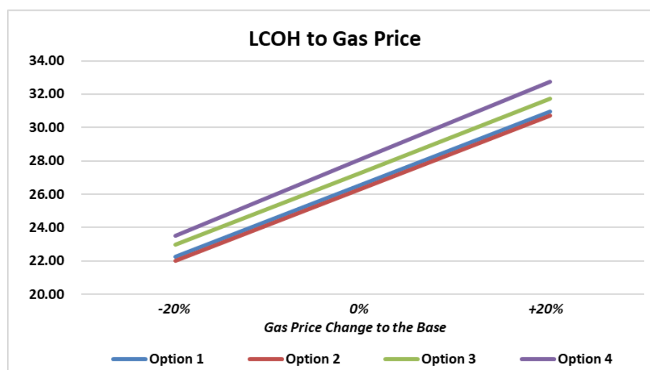
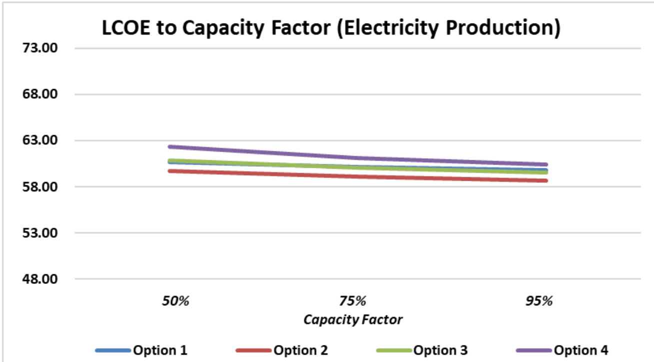


Exhibit 197 LCOE & LCOH Sensitivity to Project 6 & 7 Capacity Factor



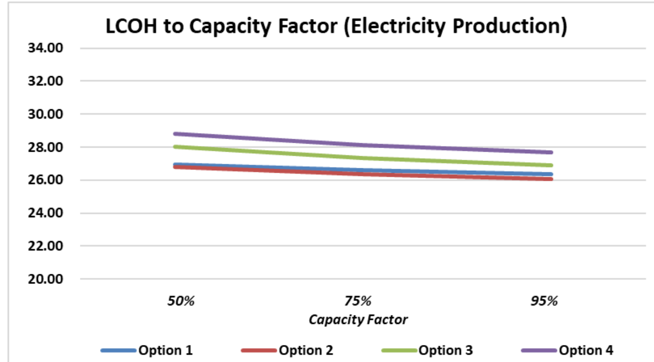
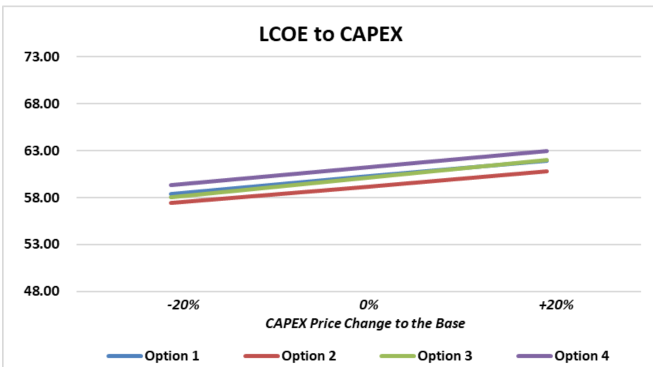


Exhibit 198 LCOE & LCOH Sensitivity to Capital Expenditures



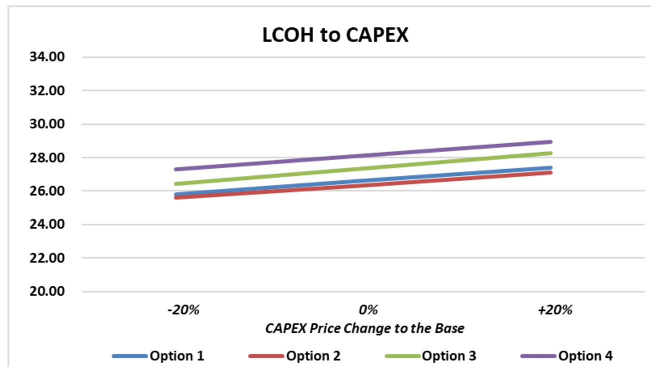
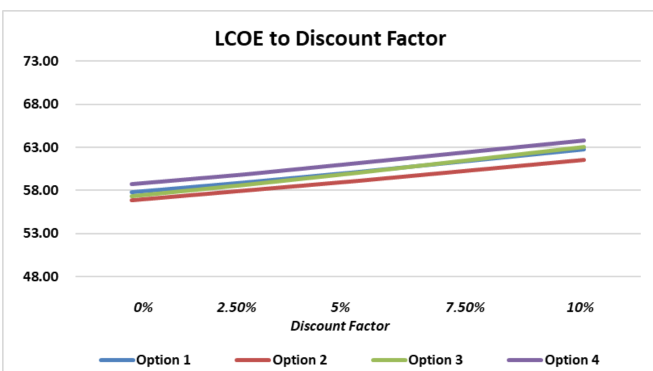
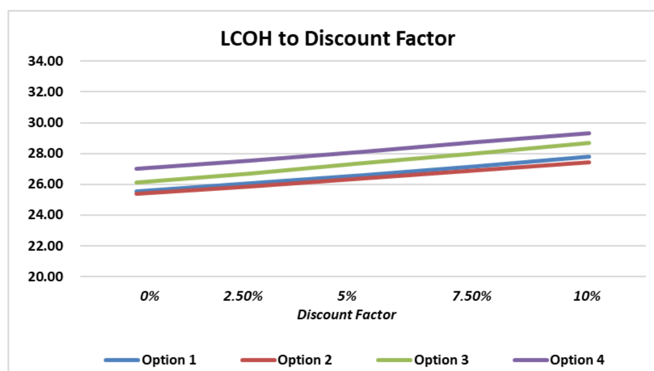


Exhibit 199 LCOE & LCOH Sensitivity to Discount Factor





8.4.5 LCOE RESULTS

Option 2 has the lowest (best) LCOE values of all the options in all the considered scenarios.

Option 1 and Option 3 LCOE results are close where Option 3 shows better results in pessimistic scenarios with high gas prices (due to the higher efficiency of Project 3).

Option 4 has the highest LCOE for all scenarios.

8.4.6 LCOH RESULTS

Option 2 has the lowest (best) LCOH values of all the options in all the considered scenarios.

Option 1 LCOH results are close to Option 2.

The LCOH of Option 3 are higher to those of Options 1 and 2, and Option 4 has highest LCOH for all scenarios.

8.4.7 RANKING OF THE OPTIONS

Ranking of the options in Exhibit 200 is based on IRR, LCOE and LCOH.

Exhibit 200 Ranking of the Options

Option		**1**	**2**	**3**	**4**
IRR	%	13.06%	14.55%	12.00%	11.38%
LCOE	USD/MWh	60.18	59.12	60.07	61.14
LCOH	USD/Gcal	26.62	26.36	27.36	28.13
Ranking					
IRR		2	**1**	3	4
LCOE		3	**1**	2	4
LCOH		2	**1**	3	4
Summary Ranking		2	**1**	3	4

Option 2 is ranked as the best option, closely followed by Option 1.

Option 2 is the best option in all sensitivity cases. Thus Option 2 appears to be a robust project since it retains its first-place ranking under many different project conditions. However, risks related to this option shall be further investigated. The risk analyses may turn Option 1 to be the optimum solution.

The reduced sensitivity of Option 3 to low gas prices may put this option in the list for further consideration as well. That said, a reduced gas price also improves the IRR and economic performance of the highest ranking Option 2 and Option 1 project.

8.5 POTENTIALLY SIGNIFICANT ENVIRONMENTAL, HEALTH, SOCIAL ISSUES

All the projects are configured with the combustion systems and/or air emissions control systems to meet or exceed European Union environmental regulations as explained below.

1. The gas turbine technologies considered for all the projects are equipped with the state-of-the-art low nitrogen oxide (NOx) combustion systems. GT1 can achieve 18 mg/Nm^3 NOx emissions, and GT2 can achieve 10mg/Nm^3 NOx emissions both at 15% O_2, which should satisfy EU NOx emissions limit of 30 mg/Nm^3.
2. The proposed RICE units will be equipped with the Selective Catalytic Reduction system (SCR), which enable them to meet the EU standard for NOx emission for the selected size of the RICE of 95 mg/Nm^3 at 15% O_2.
3. All Projects will be utilizing natural gas as a primary fuel, with the Ultra-Low Sulfur Diesel (ULSD) as a backup fuel to meet the Euro V standard for fuel. While Moldova as an EU accession country have been granted certain temporary exemptions to allow for transition to the ULSD, it is expected that Moldova will have to fully comply with the EU environmental regulations by 2030, when the projects are envisioned to be commissioned.

The CO_2 emissions in Exhibit 201 for each option are estimated based on emission factor when firing natural gas of 0.2008 tCO_2/MWh_{fuel} [76].

Exhibit 201 CO2 Emissions

	Units	Option 1	Option 2	Option 3	Option 4
CO_2 Emissions	t/y	1,921,988	1,974,131	1,560,696	1,466,104
CO_2 Emissions,	t/MWh-el, Net	0.46025	0.45296	0.47522	0.51426
Relative Specific Emissions	%	+2%	0	+5%	+14%

Note: Specific CO_2 Emissions (t/MWh-el net) are estimated by allocating all consumed fuel to electric power generation. However, all options generate the same amount heat but different amount of electric power. Thus, this approach provides for a fair relative compression of the options.

Options 2 is estimated to have the lowest specific CO_2 emissions per the MWh net of generated electric power. It is followed by Option 1. Option 4 is estimated to result in notably higher specific CO_2 emissions.

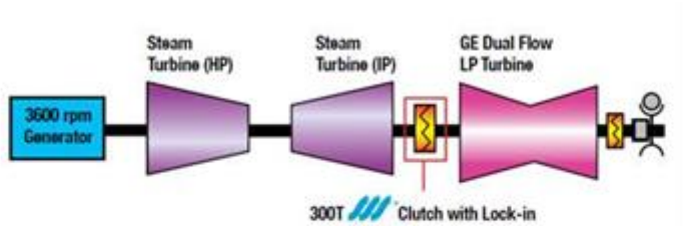
8.6 FINDINGS AND RECOMMENDATIONS

Option 2 is ranked as the best option, closely followed by Option 1 based on the Base case assumptions. Option 2 is also the best option in all sensitivity cases. Thus Option 2 appears to be a robust project since it retains its first-place ranking under many different project conditions. However, risks related to this option shall be further investigated. The risk analyses may turn Option 1 to be the optimum solution. Based on the above, Option 1 and Option 2 are recommended for further evaluation by the detailed study in the CLIN02 phase of the project.

The following potential enhancements of Option 1 and Option 2 configurations are recommended for evaluation by the detailed study.

1. Project 5 CHP units in this report are based on the RICE engines. Gas turbines can also be considered as a prime mover for this type and size of CHP units. An economic evaluation comparing RICE engine against a gas turbine for Project 5 units should establish the most economically advantageous technology for this application.
2. Project 1 and Project 2 as part of Option 1 and Option 2 utilize condensing type steam turbines with district heating extractions. When operating in CHP mode, this type of steam turbines has lower efficiency as compared to a backpressure type steam turbine (such as utilized in Project 3). However, backpressure steam turbines can only generate electric power when there is a sufficient heat load. A clutch between IP and LP sections of a steam turbine (Exhibit 202) can convert a steam turbine to condensing mode during the summer and a backpressure mode during the heating season. This technology has a potential for improving overall fuel utilization, but at higher CAPEX. A tradeoff assessment of operating versus capital cost of utilizing steam turbine clutch technology is recommended for the detailed phase of the study

Exhibit 202 Clutch Technology for steam turbines



3. Additional improvements of fuel utilization efficiency can be achieved by installing heat exchange surfaces in steam turbine condenser to preheat returning circulating district heating water and makeup water. Application of this technology can be evaluated during the detailed phase of the study.

9 REFERENCES

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24 Moldelectrica SA, ANRE, e-mail July 2019

25 SA Moldelectrica: http://www.moldelectrica.md/ru/network/annual_report http://www.moldelectrica.md/ru/activity/operative_info

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53Transnistria is an unrecognized state that split off from Moldova after the dissolution of the USSR. The Region is mostly a narrow strip of land between the Dniester River and the Ukraine. All UN member countries consider Transnistria to be part of Moldova.

54 Annex no.1 to the Government Decision no. 199 of 20 March 2014

55 Acquis represents the accumulated legislation, legal acts and court decisions that constitute the body of European Union law.

56 The date herein shall be understood to be 1 May 2019.

57 According to the Decision, "practically all the tributaries have the quality class V, which indicates that the tributaries of the Dniester River on the right side, within the boundaries of the Republic Moldova, are highly polluted and their water can only be used directly for electricity generation and transport purposes, the water requiring prior treatment for other purposes".

58 The World Bank Report No. PAD3147, April 9th, 2019, Project Appraisal Document On A Proposed Credit

59 In June 2019, the privately-owned distribution company RED Union Fenosa was sold by Naturgy to a financial investor

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61 The Republic of Moldova ANRE report of 2018

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Conceptualization Study Report CLIN 01

Appendices

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LIST OF EXHIBITS

A. LIST OF RELEVANT POINTS OF NATURAL GAS TRANSMISSION NETWORK OF MOLDOVATRANSGAZ

Exhibit A-1 List of interconnection points of the natural gas transmission network of Moldovatransgaz,

Name of points	Point Type	Direction	Capacity m3/d
Entry Points			
Alexeevca (ACB)	In	UA	24900000
Grebeniki (ATI)	In	UA	80200000
Grebeniki (RI, SDKRI)	In	UA	30000000
Limanscoe (TO 3)	In	UA	9000000
Ungheni (IUC)	In	MOL	5000000
Ananiev (ACB)	In	UA	48000000
Exit Points			
Alexeevca (ACB)	Out	UA	24900000
Limanscoe (TO 3)	Out	UA	9000000
Causeni (ATI)	Out	MOL	80000000
CauSeni (RI, SDKRI)	Out	MOL	25000000
Ungheni (IUC)	Out	MOL	5000000
Points to final consumers directly connected to the network			
SAAGNC Chisinau-2	Out	MOL	134400
SAAGNC Balti-1	Out	MOL	187000
SAAGNC Orhei -1	Out	MOL	167000
SAAGNC Drochia	Out	MOL	443000
SAAGNC Hincesti	Out	MOL	192000
SAAGNC Comrat	Out	MOL	88000
Connection points to the distribution system			
GRS Drochia	Out	MOL	221000
GRS Pervomais	Out	MOL	56000
GRS Sofia	Out	MOL	56000
GRS Soroca	Out	MOL	205000

Name of points	Point Type	Direction	Capacity m3/d
GRS Suri	Out	MOL	38000
GRS Parcani	Out	MOL	37000
GRS Edinet	Out	MOL	216000
GRS Cupcini	Out	MOL	2013000
GRS Briceni	Out	MOL	211000
GRS Ocnita	Out	MOL	216000
GRS Frunze	Out	MOL	56000
GRS Otaci	Out	MOL	216000
GRS Hadarauti	Out	MOL	19000
GRS Bârladeni	Out	MOL	56000
GRS Donduseni	Out	MOL	147000
GRS Orhei	Out	MOL	1213000
GRS Peresecina	Out	MOL	211000
GRS Soldanesti	Out	MOL	147000
GRS Berezlogi	Out	MOL	211000
GRS Rezina Linia Oras	Out	MOL	214000
GRS Rezina Linia Ciment	Out	MOL	2191000
GRS Chistelnita	Out	MOL	52000
GRS Seliste	Out	MOL	211000
GRS Cotiujeni	Out	MOL	56000
GRS Chiperceni	Out	MOL	52000
GRS Telenesti	Out	MOL	52000
GRS Calarasi	Out	MOL	211000
GRS Raciula	Out	MOL	52000
GRS NiGRSoreni	Out	MOL	45000
GRS Ungheni	Out	MOL	669000
GRS Morenii Noi	Out	MOL	52000
GRS Todiresti	Out	MOL	52000
GRS Cainari	Out	MOL	52000

Name of points	Point Type	Direction	Capacity m3/d
GRS Stefan Voda	Out	MOL	491000
GRS Ermoclia	Out	MOL	211000
GRS Causeni	Out	MOL	211000
GRS Saiti	Out	MOL	52000
GRS Tocuz	Out	MOL	52000
GRS Rascaietii Noi	Out	MOL	52000
GRS Olanesti	Out	MOL	52000
GRS Nistru	Out	MOL	52000
GRS Cosnita	Out	MOL	211000
Hirbovat	Out	MOL	10000
Copanca	Out	MOL	7000
Hagimus	Out	MOL	4000
Fârladeni	Out	MOL	3000
GRS Basarabeasca	Out	MOL	230000
GRS Sadaclia	Out	MOL	53000
GRS Cimislia	Out	MOL	712000
GRS Gura Galbenei	Out	MOL	52000
GRS Hincesti	Out	MOL	211000
GRS Carpineni	Out	MOL	52000
GRS Tvardita	Out	MOL	199000
GRS Ferapontievc	Out	MOL	55000
GRS Cantemir	Out	MOL	52000
GRS Comrat Linia Oras	Out	MOL	876000
GRS Comrat Linia	Out	MOL	261000
GRS Dezghingea	Out	MOL	59000
GRS Leova	Out	MOL	231000
GRS Ceadir-Lunga Linia Oras	Out	MOL	226000
GRS Ceadir-Lunga Linia Sat	Out	MOL	209000
GRS Taraclia	Out	MOL	223000

Name of points	Point Type	Direction	Capacity m3/d
Cairaclia	Out	MOL	203000
GRS Burlaceni Linia Burlaceni	Out	MOL	52000
GRS Burlaceni Linia Ciumai	Out	MOL	52000
GRS Vulcanesti	Out	MOL	234000
GRS Gavanoasa	Out	MOL	54000
GRS Cahul	Out	MOL	1000000
GRS Etulia	Out	MOL	52000
GRS Cismichioi	Out	MOL	166000

Source: Annex to the decision of the ANRE Board of Directors of no. 414/2017 of October 26, 2017

B. NATURAL GAS CHARACTERISTICS

Moldovatransgaz operates a chemical testing laboratory, with branches in the Drokievsky, Causeni Chisinau. The laboratory possess accreditation from National Accreditation Center MOLDAC for compliance with SM SR EN ISO / CEI 17025: 2006 General requirements for the competence of testing and calibration laboratories. The laboratory determines the set of physical and chemical paraments according to GOST 5542 "Technical Conditions of Natural Fuel Gases for Industrial and Domestic Purposes". The gas quality is monitored in both ACB and RI directions. The analysis of the quality of natural gas is carried out continuously and around the clock. Based on the results of hourly analyzes of the natural gas physical characteristics, daily average values are calculated, based on which the "Quality Certificate for Natural Gas" is compiled. Archived certificates are available on Moldovatransgaz web site. Data from natural gas quality certificates from ACB (Exhibit B-1) and RI-SDKR (Exhibit B-2) are presented in the tables below. Data presented for the one-year period demonstrates that the quality of the natural gas is consistent.

Exhibit B-1 Natural gas quality certificates data for ACB trunk line by Moldovatransgaz

COMPONENT	UNIT	24-JAN-2018	31-JUL-2019
Methane	%mol	96.320	95.840
Carbon dioxide	%mol	0.140	0.197
Nitrogen + Oxygen	%mol	0.685	0.718
Ethan	%mol	1.964	2.273
Propane	%mol	0.644	0.712
i-Butane	%mol	0.102	0.107
n-Butane	%mol	0.098	0.105
Neopentane	%mol	0.002	0.002
i-Pentane	%mol	0.018	0.019
n-Pentane	%mol	0.012	0.014
Hexane	%mol	0.013	0.017
Oxygen	%mol	0.008	0.007
Dew point	°C@3.92MPa	-22.8	-15.4
LHV	kcal/m3	8170	8195
Wobbe Index	kcal/m3	11905	11907
Specific gravity	-	0.5787	0.5819
Density	kg/m3	0.6970	0.7008
Mercaptan	gr/m3	<0.0002	<0.0002
H2S	gr/m3	<0.0001	0.0002
Solids	gr/m3	-	-
Odorization	%	100	100

Exhibit B-2 Natural gas quality corticates data for RI-SDKRI trunk by Moldovatransgaz

COMPONENT	UNIT	24-JAN-2018	31-JUL-2019
Methane	%mol	96.322	95.785
Carbon dioxide	%mol	0.150	0.197
Nitrogen + Oxygen	%mol	0.701	0.659
Ethan	%mol	1.987	2.336
Propane	%mol	0.611	0.748
i-Butane	%mol	0.096	0.114
n-Butane	%mol	0.093	0.111
Neopentane	%mol	0.001	0.001
i-Pentane	%mol	0.017	0.020
n-Pentane	%mol	0.012	0.015
Hexane	%mol	0.009	0.014
Oxygen	%mol	0.009	0.007
Dew point	°C@3.92MPa	-23.8	-15.5
LHV	kcal/m3	8162	8210
Wobbe Index	kcal/m3	11897	11922
Specific gravity		0.5783	0.5824
Density	kg/m3	0.6966	0.7015
Mercaptan	gr/m3	<0.0002	<0.0002
H2S	gr/m3	0.0003	0.0002
Solids	gr/m3	-	-
Odorization	%	100	100

Natural gas quality certificates for Iasi - Ungheni pipeline are not available. However, the natural gas is supplied is via NTS Transgaz network. NTS Transgaz has minimum quality requirements for natural gas to be transmitted/traded thru its network (Exhibit B-3).

Exhibit B-3 Transgaz minimum quality requirements of the traded natural gas, at the entry / exit points of the NTS,

COMPONENT	UNIT	VALUE
Methane	%mol	min 70
Ethane	%mol	max 10
Propane	%mol	max 3.5
Butane	%mol	max 1.5
Pentane	%mol	max 0.5
Hexane	%mol	max 0.1
Heptane	%mol	max 0.05
Octane and higher hydrocarbons	%mol	max 0.05
Nitrogen	%mol	max 10
Carbon dioxide	%mol	max 8
Oxygen	%mol	max 0.02
H_2S	mg/m^3	max 6.8
Mercaptan	mg/m^3	min 8
total sulfur for a short period	mg/m^3	max100
Dew point of water	°C@pressure	max -15
Dew point of hydrocarbons	°C@pressure	max 0
HLV	$Kcal/m^3$	max 7840
Solids	g/m^3	max 0.05

C. MOLDOVA ENERGY STRATEGY FOR GAS SECTOR

C.1 BACKGROUND INFORMATION

Moldova power generation relies almost 100% on fossil fuel. In general Moldova lacks energy resource, thus the country depends on imports of natural gas for power and heat generation. Electricity is also imported from Ukraine. Natural gas is imported from Russia via existing transit pipelines thru Ukraine, and from Romania via Iasi (Romania)-Ungheni (Moldova) interconnector. Since 2010, Moldova is a member of the Energy Community. In 2014 Moldova had signed an Association Agreement with EU. The signed agreement is consistent with the Moldova's legislation related to power, oil, gas, environment, competition, renewables, efficiency and reporting that conforms with the EU regulations. In addition, Moldova is currently executing a project for the synchronization of its power network with ENTSO-E to connect to the European power market. In terms of natural gas, Moldova has the status of "Observer" in ENTSO-G.

C.2 COUNTRY ENERGY STRATEGY IN NATURAL GAS SECTOR

In 2013 Moldova accepted the country Energy Strategy through 2030. The Strategy outlines strategy for the development of the country energy sector and particularly its gas sector with the following goals.

- Develop and modify the country infrastructure to enable bi-directional gas transit to and from EU countries
- Diversify natural gas supply sources
- Integrate natural gas market with the EU market

Moldova had set the year 2020 in its Energy Strategy as the target to have operating interconnections with the EU, including the energy market liberalization. In fulfilling the strategy targets for natural gas (Strategy National Development Program "Moldova 2020" and the National Program for Energy Efficiency 2011-2020), the following results are to be achieved by 2020:

- Completion of 40 km of natural gas lines to improve the country energy security
- Reduction of losses in transport and distribution networks

The specific strategic objectives for 2013-2020 and related measures outlined in the Strategy related to natural gas are:

"Objective no.1. Ensuring the security of the natural gas supply by diversifying the routes and sources of supply, the types of carrier (conventional, unconventional gas, liquefied natural gas) and through storage deposits, concomitantly with the consolidation of the role of the Republic of Moldova as natural gas transit corridor."

The strategy targets several actions to be completed and implemented to accomplish the objectives:

- Improvement of country interconnections: Moldova has two neighboring countries, which can supply natural gas from few sources. Existing interconnections with Romania allow both straight (Transbalkan) and reverse flow (Iasi-Ungenhi). Currently the connections with Ukraine allows supply direction towards Moldova only. Further activity is to solidify

Moldova's role as natural gas transit country in both directions: Ukraine-Romania and Romania-Ukraine.

- Identification of alternates to existing suppliers. Presently, Moldova is supplied with natural gas from Russia, and partially from Romania. Ukraine has offshore gas reserves and still unexploited shale gas reserves. Both Romania and Ukraine are working to diversify their supply sources and developing their own gas reserves. LNG has also supply potential via existing Mediterranean LNG terminals and the existing and the near future SEE interconnections. Additional sources of natural gas supply would be pipelines currently in construction in SSE.
- Search for additional in-country resources and optimize their use. Moldova in general lacks reserves of natural gas, however there are areas in the country that need to be re-evaluated with state-of-art investigation practices and technics. There is no gas storage facility in Moldova. There is a possibility of developing a gas storage. It'll require an agreement with a neighboring country to use or to invest in new or existing facility either in Romania or Ukraine.

"Objective no.5. Ensuring the legislative, institutional and operational framework for real competition, effective opening of the market, establishing the energy price in a transparent and equitable way, integration of the energy market of the Republic of Moldova with the EU market."

Moldova has partially completed this objective by:

- Liberalizing its energy market
- Revising the primary legislation to account the roles of ANRE, TSO, DSO, SO
- Defining the price mechanisms in line with the free market framework
- Creating competition in the energy market
- Monitoring the TSOs investments to maintain the energy transmission system to ensure the security of supply

C.3 ENERGY COMMUNITY FOR MOLDOVA

Moldova is a Contracting Party of the Energy Community. The following sections a status of Moldova natural gas market compiled by the Energy Community.

C.3.1 Interconnectivity

The natural gas transit route thru Moldova is of high importance to countries in SSE and Turkey. Moldova is transiting about 20 bcma south to Western Balkans. The natural gas supply to Moldova, is in need of diversification. As a result, an interconnector (Iasi-Ungheni) with Romania was built. The interconnector is to be extended to Chisinau. Vestmoldtransgaz is the interconnector operator. Vestmoldtransgaz was sold to Transgaz, Romania in 2018 with commitment to build the extension to Chisinau. The Energy Community is assisting Moldovatransgaz to implement the interoperability concept and to conclude an interconnection agreement with Ukraine.

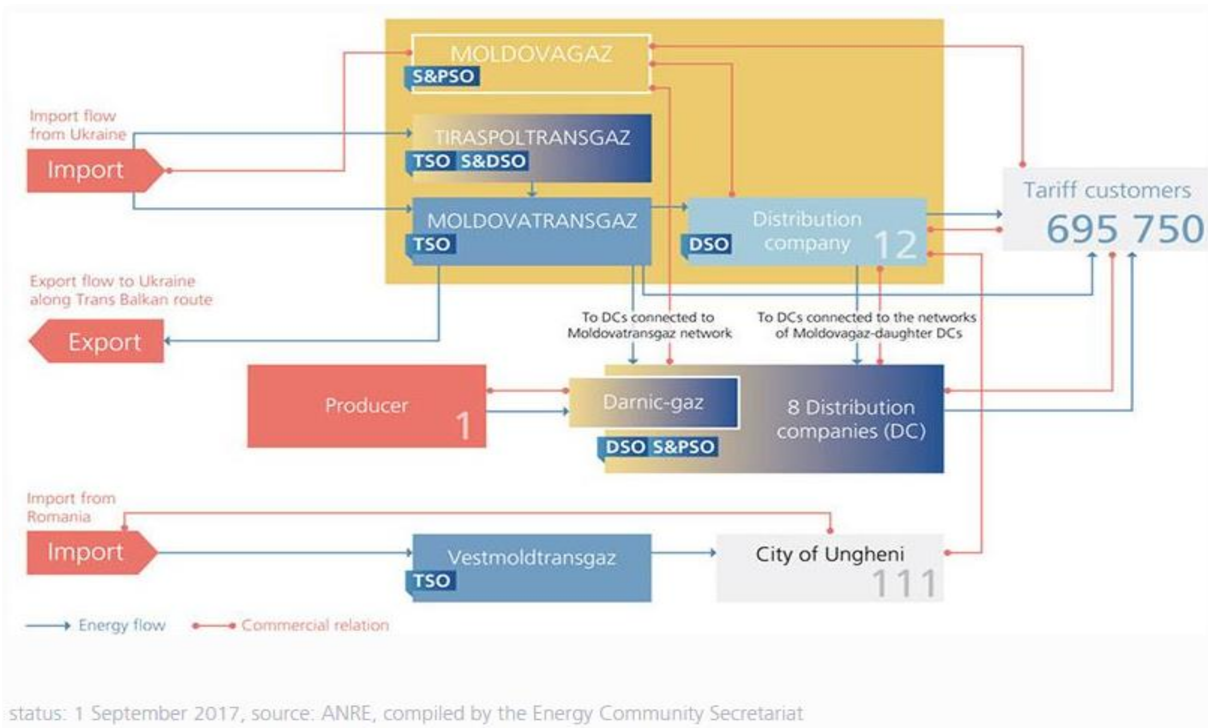
C.3.2 Third Party Access

Moldova legislation adopted the concept of third-party access to the natural gas network. The law requires transmission tariff methodology to be established for that access. This methodology is under development. The current legislation requires an allocation of monthly and annual capacity for time-horizons up to five years and that interruptible capacity is offered in case of contractual congestion. Secondary market trade of capacities is also in place.

C.3.3 Wholesale Market

Major gas market activities in the country remain concentrated within Moldovagaz. The company is responsible for gas imports from Russia and control over the country's two gas TSO.

Exhibit C-1 Moldova natural gas market scheme, by Energy Community



C.3.4 Retail market

Moldovagaz dominates the distribution market with its 12 subsidiaries, which makes about 70% of market share. The customers can select and change their gas supplier. Rules and procedures for supplier switching are in place. End-user price regulation is applied to all customer categories. Household and small industrial customers are benefiting from the regulated market supply.

C.3.5 Balancing

Moldova's legislation requires TSO to perform balancing of the system by implementing a certain set of rules. To date these rules are not implemented in Moldova.

C.4 ANRE

ANRE is the National Agency for Energy Regulation of Moldova. ANRE was established in 1997. ANRE's duties and responsibilities have expanded, and its role as a regulator has been solidified. Presently ANRE is driving implementation of the Moldova energy policy. ANRE is ensuring energy market regulation, under conditions of accessibility, availability, reliability, continuity, competitiveness and transparency. ANRE basic functions can be summarized as follows:

- Elaborates and approves regulations, methodologies and other norms in the energy field in the cases provided by the legislation in force
- Supervises the energy sectors and the compliance of the companies in the energy sector with the existing regulations.
- Promotes, monitors and ensures fair competition in the regulated sectors.
- Issuing licenses for the energy markets operators, in accordance with Law no. 174 of September 21, 2017 on energy, Law no.461-XV of July 30, 2001 on the market of petroleum products, Law no.107 of May 27, 2016 on electricity, Law no.108 of May 27, 2016 on natural gas and Law no. 160 of July 22, 2011 authorization of the entrepreneurial activity.
- Monitor and control, within the established laws, the compliance by the licensees in carrying out the authorized activities
- Modify, suspend and withdraw licenses in cases and according to the procedure provided by the laws
- Promotes an appropriate tariff policy, which is in line with market economy principles, to ensure the protection of the rights of final consumers and the profitability of energy sector enterprises.
- In the cases stipulated by the law, ANRE approves the tariffs calculated according to the methodologies approved by ANRE and monitors the correctness of their application.
- Supervise the observance of the principle "maximum efficiency at minimum costs" by the companies in the energy sector when calculating tariffs for regulated activities and submitting them for approval.
- ANRE promotes the protection of consumers legal rights and interests, exercises control over how consumers rights are respected, examines consumer complaints, and resolves misunderstandings between consumers and suppliers, within the limits of its competencies.

A list of license holders for TSO, DSO, SO operations in Moldova related to natural gas market are presented in Exhibit C-2

Exhibit C-2 List of license holders in natural gas sector issued by ANRE

Licensee	License validity
NATURAL GAS TRANSPORT	
"MOLDOVATRANSGAZ" SRL	30.11.2024
"VESTMOLDTRANSGAZ" SRL	06.01.2040
natural gas supply	
"BELVILCOM" SRL	11.06.2029
IM "ROTALIN GAZ TRADING" SRL	24.08.2035

Licensee	License validity
ISC "NORD GAZ SINGEREI" SRL	22.10.2035
"MOLDOVAGAZ" SA	06.11.2043
“DARNIC-GAZ” SA	11.04.2038
"PROALFA-SERVICE" SRL	23.06.2034
"PIELART SERVICE" SRL	28.12.2034
FPC "LACATUS" SRL	07.06.2037
"TIM INVEST" SRL	03.01.2038
IM "SEF-GAZ" SRL	01.02.2038
"CANTGAZ" SRL	12.12.2041
"NORD-UNIONGAZ" SRL	27.03.2042
"SALCIOARA-VASCAN" SRL	25.04.2042
"PARTENER-GAZ" SRL	23.02.2036
"ENERGOCOM" SA	16.01.2043
NATURAL GAS DISTRIBUTION	
”CHISINAU-GAZ” SRL	15.11.2024
“EDINET-GAZ” SRL	16.11.2024
"FLORESTI-GAZ" SRL	17.11.2024
"IALOVENI-GAZ" SRL	17.11.2024
"STEFAN VODA-GAZ" SRL	18.11.2024
“UNGHENI-GAZ” SRL	23.11.2024
"CAHUL-GAZ" SRL	23.11.2024
"BALTI-GAZ" SRL	24.11.2024
"ORHEI-GAZ" SRL	24.11.2024
"CIMISLIA-GAZ" SRL	13.12.2024
"GAGAUZ-GAZ" SRL	20.01.2025
"TARACLIA-GAZ" SRL	05.06.2025
"DARNIC-GAZ" SA	23.02.2026
"BELVILCOM" SRL	23.02.2026
"MOLDOVATRANSGAZ" SRL	17.12.2029

Licensee	License validity
IM "ROTALIN GAZ TRADING" SRL	24.08.2035
ISC "NORD GAZ SINGEREI" SRL	22.10.2035
"PROALFA-SERVICE" SRL	23.06.2034
"PIELART SERVICE" SRL	28.12.2034
FPC "LACATUS" SRL	07.06.2037
"TIM INVEST" SRL	03.01.2038
IM "SEF-GAZ" SRL	01.02.2038
”BV GROUP COMPANY” SRL	02.12.2041
”DOBOS COMPANY” SRL	27.03.2042
”CANDELUX COM” SRL	25.04.2042
SUPPLY OF COMPRESSED NATURAL GAS FOR VEHICLES AT FILLING STATIONS	
IM "ROMPETROL MOLDOVA" SA	28.02.2027
"TRANSAUTOGAZ" SRL	15.05.2028
"OLTAVIM" SRL	13.02.2029
"SALTICA-LUX" SRL	28.03.2029
ICS "LUKOIL-MOLDOVA" SRL	18.04.2029

D. GAS RESERVES AND PRODUCTION IN MOLDOVA'S NEIGHBOURING COUNTRIES

D.1 UKRAINE

D.1.1 Gas Transit

The volume of transit in 2018 amounted to 86.8 bcm, which is 6.7 bcm (or 7.2%) less than in 2017. The transit flow decreased unevenly by exit points – about 65% or 4.3 bcm of total decline in transit volume was due to a decrease in transmission to Slovakia. The volumes of transit flows in 2018 were higher than those of 2017 in only two periods – during a cold snap in March 2018, and during the maintenance of the Yamal and the Nord Stream pipelines in July 2018. In Q1 2018, the Nord Stream became the main route for supplying Russian gas to the EU (36% of total supply), slightly exceeding transit through Ukraine (34%).

Exhibit D-1 Volumes of natural gas transit thru Ukraine 2014-2018

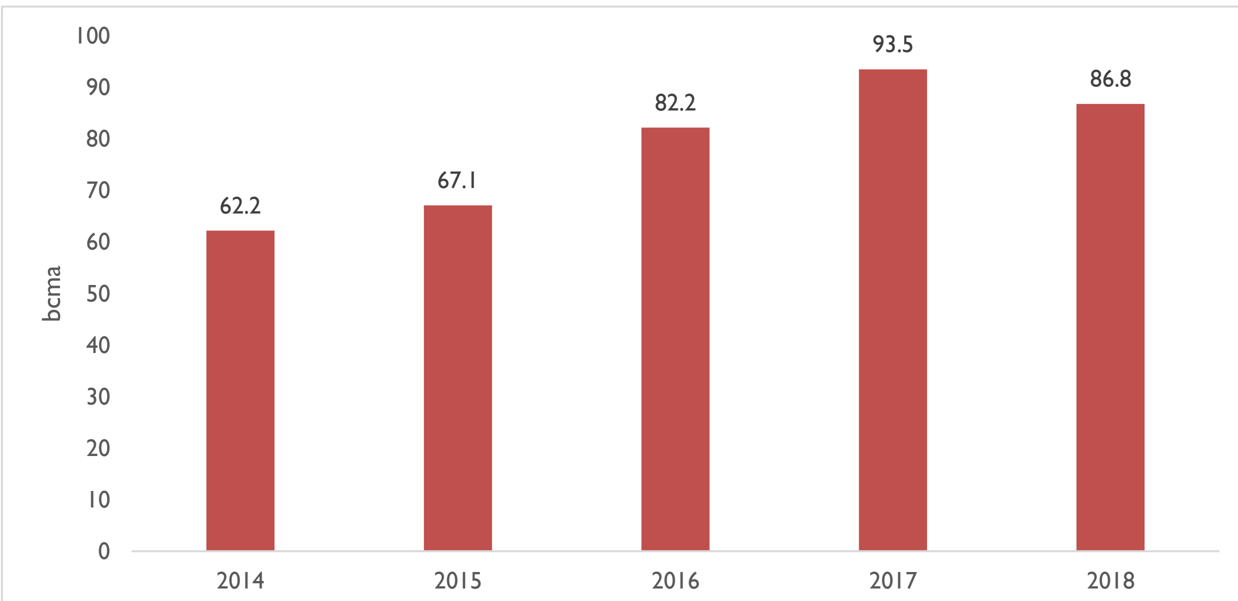
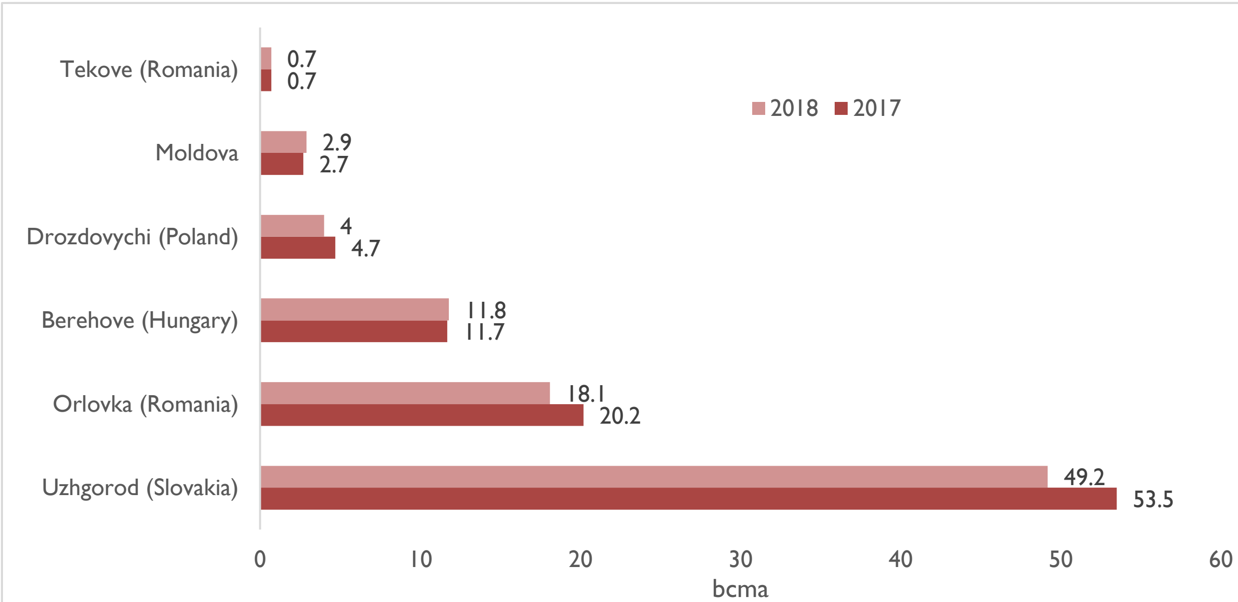


Exhibit D-2 Distribution of transit flows by exit points in 2017-2018



D.1.2 Gas Production

In 2018 Ukraine had produced 450mcm more than in 2017, the increase is due to:

- 245mcm increase in production by Ukrgasvydobuvannya
- 233mcm increase by private producers

The Ukrainian company dealing with gas production, Ukrgasvydobuvannya part of the Naftogas group, successfully completed a program to offset the natural decline in gas production of about 1bcma through the implementation number of technical measures. Ukrgasvydobuvannya has extensive program to increase natural gas production to 20.1bcm in 2020.

D.1.3 Gas Imports

In 2018, imported gas to Ukraine was exclusively from the European gas market. Compared to 2017, gas imports decreased by 25%. In 2018, Naftogas purchased natural gas from 18 European suppliers (13 in 2017). None of these companies supplied more than 30% of the volume imported by Naftogas. 65 companies imported gas to Ukraine in 2018 (67 companies in 2017).

The Slovak direction remained the major gas supply route to Ukraine while the share of supplies through Hungary increased for the second consecutive year. Although Ukraine's annual need in gas imports is fully covered by the available reverse capacities, gas supplies to Ukraine from neighboring countries are still not in line with European rules: relations with operators of the adjacent gas systems and Gazprom are not in line with European and Ukrainian energy legislation.

D.1.4 Gas Consumption

Ukraine's total gas consumption in 2018 increased by 1.3%, from 31.9 to 32.3 bcm, compared to 2017. Households used 10.6 bcm of gas, 0.6 bcm less than in 2017. Meanwhile, gas consumption by district heating companies for household needs amounted to 4.8 bcm in 2018, 0.2 bcm more than 2017. Heat generation for public sector and the industrial sector accounted for 2.3 bcm, which is 0.4 bcm more than in 2017.

D.1.5 Alternatives

Ukraine has Europe's 3-largest shale gas reserves at about 1.2 tcm. There are two potential shale gas fields. The Yuzivska gas field located in Donetsk and Kharkiv Regions. The other promising field, Olesska, is in Lviv and Ivano-Frankivsk Regions. In 2013, Ukraine signed a shale gas 50-year production sharing agreement with Royal Dutch Shell for Yuzivska gas field, however at present the contract is on hold.

D.1.6 Market

Ukraine continues fundamental reforms of its gas market. Many of the major disadvantages of the previous market model have been almost completely eliminated, but a number of problems remain unresolved. The key remaining problems include lack of competition in retail, accumulation of debt for unauthorized offtake, and administrative regulation of gas prices.

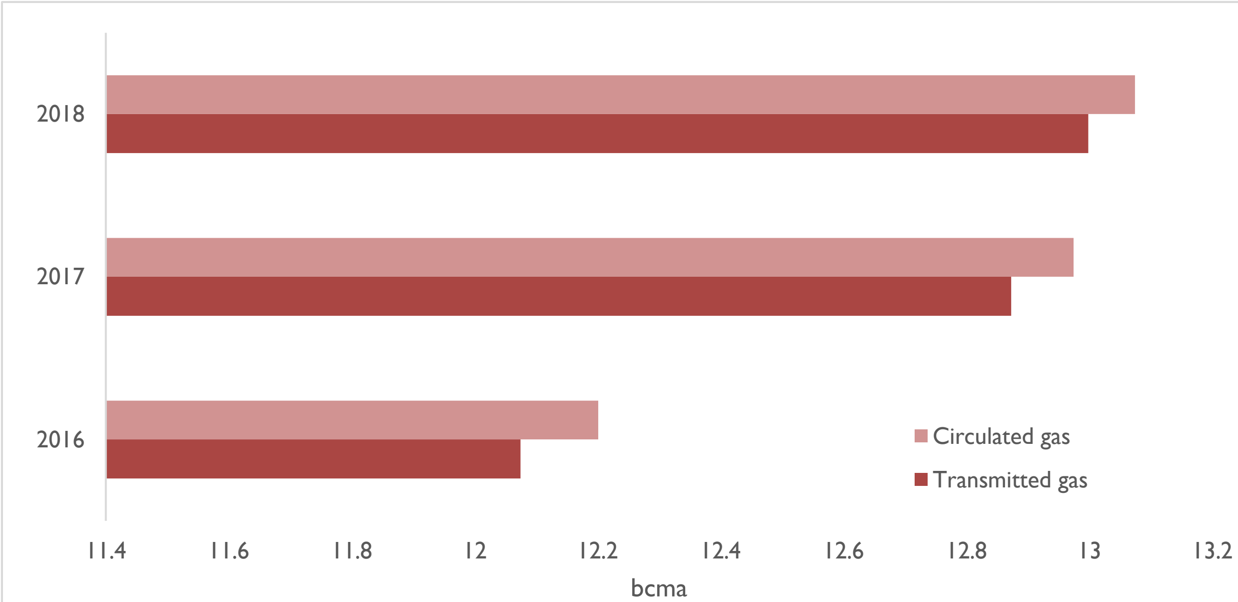
D.2 ROMANIA

Natural gas market on Romania is liberalized, as result of this there are:

- One (1) National Transport System operator – SNTGN Transgaz SA Medias
- Six (6) gas producers: Petrom, Romgaz, Amromco, Toreador, Wintershall Medias, and Aurelian Oil & Gas
- Three (3) Operators for underground gas storage: Romgaz, Amgaz, Depomures
- 34 natural gas distribution and supply companies - the largest being Distrigaz Sud and E.ON Gaz Romania
- 76 suppliers on the wholesale market

SNTGN Transgaz is the technical operator of the National Gas Transmission System (NTS) ensuring the transmission, of over 90% of the natural gas consumed in Romania, in accordance with the EU standards of performance and environment.

Exhibit D-3 SNTGN Transgaz transmitted and circulated natural gas quantities 2016-2018



D.2.1 Gas Production

Natural gas production increases gradually, being higher by 3.39% e.g. 175 mcm greater than the production recorded in 2017 (5.333 mcm in 2018 vs 5.158 mcm in 2017). This production, according to estimates, ensured Romgaz a 50.67% market share of internal gas deliveries for consumption, and a 45.98% market share of deliveries for the total consumption of Romania.

D.2.2 Market

Romania has the largest market for natural gas in Central Europe. The natural gas market reached record size in the early 1980s, following the implementation of government policies aimed at eliminating the dependency on imports. The application of these led to development of in-country resources.

The natural gas market in Romania has been gradually liberalized benefiting from structural, institutional and legislative changes. The liberalization process was accompanied by the following measures designed to lead to the development of the market:

- Granting licenses and authorizations to the economic agents in the sector
- Authorization of specialized personnel in the field
- Elaboration of specific technical and commercial regulations
- Implementation of new pricing methodologies, which aimed to stimulate licensed operators to make investments and reduce operational costs
- Monitoring and control of the activity of authorized and licensed economic agents

The natural gas market in Romania is set in two segments: competitive and regulated segments. The competitive segment includes commercialization of natural gas between suppliers. The regulated segment includes activities of natural monopoly carried out under the framework contracts and supply at regulated prices. A Market Operator was designated as part of the National Natural Gas Dispatcher of Bucharest (a structure of SNTGN Transgaz SA Medias) to ensure a framework of natural gas allocation in a fair and non-discriminatory way. The current Market Operator:

- Establishes monthly percentages of the natural gas mixture from domestic production and the import requirement for all licensed gas suppliers / distributors, as well as for eligible consumers
- Monitors daily purchases / consumption of internal gas / import
- Prepares monthly reports on the purchases of natural gas from the domestic production and from imports by each operator on the gas market in Romania and by each eligible consumer.

E. FUTURE GAS INFRASTRUCTURE DEVELOPMENTS IN MOLDOVA AND IN THE REGION

E.1 FUTURE NATURAL GAS INFRASTRUCTURE DEVELOPMENT IN THE COUNTRY

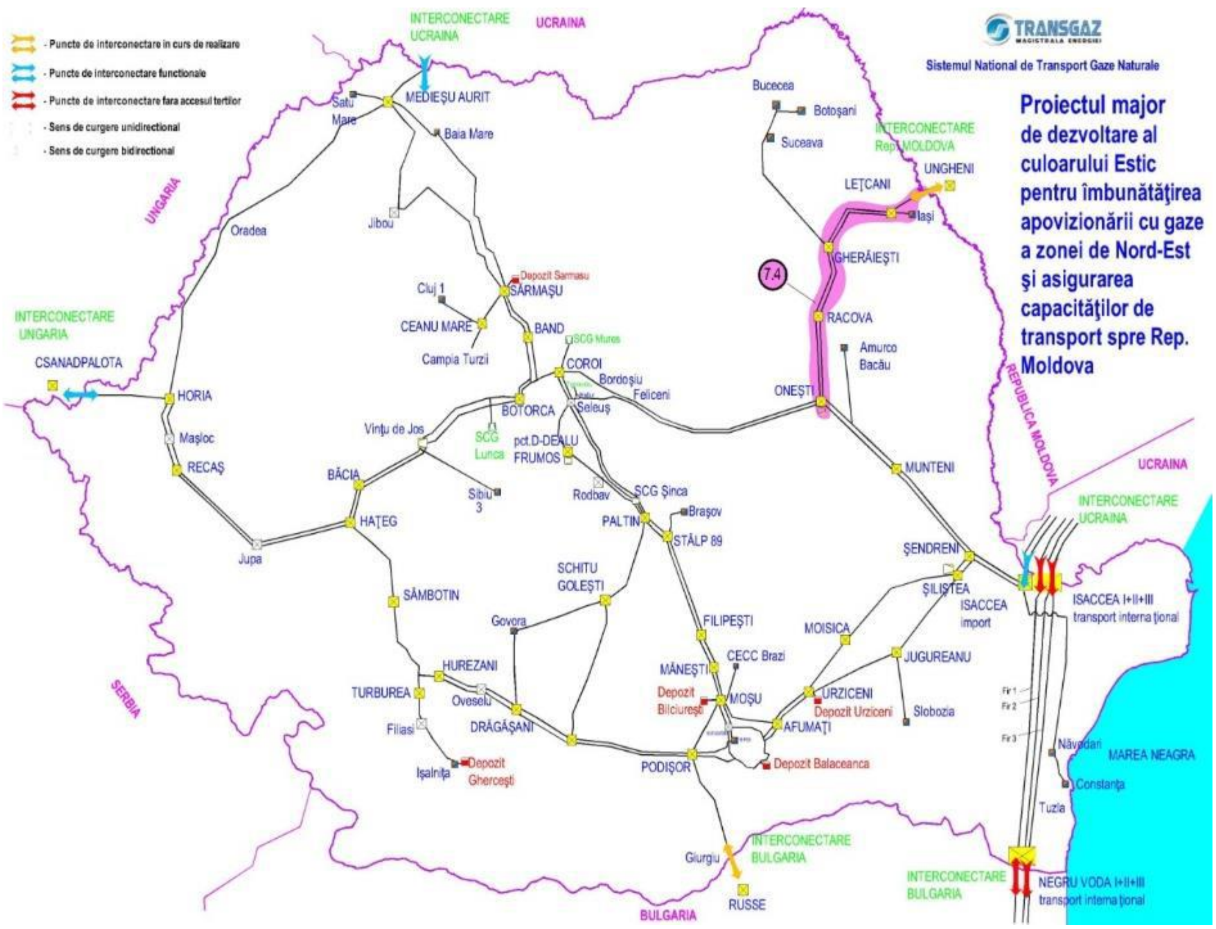
Currently the Ungheni – Chisinau gas pipeline is under construction, DN600, PN 5.5MPa, L=120km, with an expected capacity 1.5 bcma. The expected completion is in 2020. The project is delivered by Vestmoldtransgaz.

E.2 FUTURE NATURAL GAS INFRASTRUCTURE DEVELOPMENT IN THE REGION

E.2.1 Support Projects for Iasi – Ungheni Interconnection

Considering the need for improving gas supply to the North-East Romania and keeping in mind the required gas transmission capacities to Moldova through the interconnection pipeline between Romania and Moldova (Iasi-Ungheni), a series of improvements need to be implemented in the Romanian gas transmission system to ensure that the required technical parameters are consistent with the gas consumption needs of the relevant regions.

Exhibit E-1 NTS developments in the North-Eastern area of Romania, by Transgaz



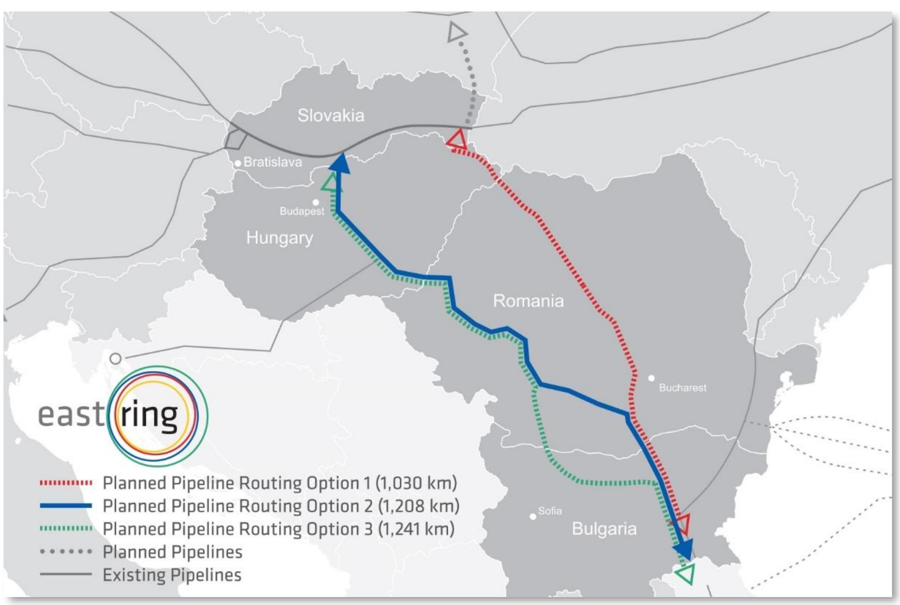
The major milestones of the Romanian gas transmission system projects are as follows:

- Construction of 104.1 km of a new DN 700 gas transmission pipeline, PN 5.5MPa, in the Onesti – Gheraesti direction. The route of this pipeline will be in parallel to the existing pipelines DN500 Onesti – Gheraesti.
- Construction of 61.05 km of a new gas transmission pipeline DN700, PN 5.5MPa, in the Gheraesti – Letcani direction. This pipeline will replace the existing DN400 pipeline Gheraesti – Iasi on the Gheraesti – Letcani section.
- Construction of a new gas compressor station at Onesti, including one operating and one back up compressors.
- Construction of a new gas compressor station at Gheraesti, including one operating and one back up compressors.
- Construction period is schedule for 2018-2020
- Commissioning/start-up is scheduled for 2019-2020
- Estimated completion date is 2020

E.2.2 Eastring Project

The Eastring project is planned to extend from Slovakia to Turkey via Hungary, Romanian and Bulgaria. The project is foreseen with DN1400 pipeline and capacity of 20bcma further expanded to 40bcma. Eastring should connect well-established as well as alternative natural gas sources from the Caspian (SGC) / Eastern Mediterranean (EeastMed) /Black Sea (BRUA)/ Middle East region. At the same time, it will be able to provide South-eastern Europe with gas from European gas hubs. The whole capacity will be available to any shipper or supplier. The Feasibility Study co-funded by the European Commission, completed in September 2018, has shown the positive results of the market testing and proves the project is feasible. The outcomes of the Feasibility Study enable its promoters to proceed to the next phases of the project.

Exhibit E-2 Map of Eastring trunk lines,



Source: Eastring

E.2.3 Turk Stream

TurkStream is an offshore pipeline that extends from Russia to Turkey under the Black Sea. Starting from Anapa, Russia, where there is a compressor and a landfall station, two 900 km pipelines go onshore at Kiyilkoy, Turkey landfall station. The pipeline connects with existing transmission network coming from Bulgaria. Exhibit E-3 shows how the natural gas from Turk Stream is intended to flow North to Bulgaria, and West to Serbia, Hungary and Austria. The branch thru the Balkans intends to use where possible, the existing transmission infrastructure with reversing the flow as well newly build infrastructure segments. It is expected the project to be able to supply natural gas back to Moldova via reversed Transbalkan pipeline. Estimated capacity is 32bcma.

Exhibit E-3 TurkStream and branch thru Balkans

Source: Anadolu Agency

E.2.4 IGB

The IGB gas pipeline (Exhibit E-4) will be connected with the Greek national gas transmission system in the area of Komotini and with the Bulgarian national gas transmission system in the area of Stara Zagora. The planned length of the pipeline is 182 km, the pipeline diameter will be 32" and the projected capacity will be up to 3 bcma in the direction from Greece to Bulgaria. Depending on the interest from the market and the capacities of the neighboring gas transmission systems, the pipeline is designed for increasing its capacity up to 5 bcma for following up the market evolution thus allowing physical reverse flow with the additional installation of a compressor station. Future connection between the IGB pipeline and the TAP is envisioned as well. The project is a key part of the strategy for greater integration of gas markets, which includes interconnection projects Bulgaria – Greece, Bulgaria – Romania, Romania – Hungary.

Exhibit E-4 ICB trunk line map

Source: ICB

E.2.5 Southern Gas Corridor Project

The Southern Gas Corridor (SGC) project (Exhibit E-5) aims to increase and diversify European energy supply by bringing gas resources from the Caspian Sea to markets in Europe. The Southern Gas Corridor comprises the following four projects:

- operation of the Shah Deniz natural gas-condensate field ("SD1" project) and its full-field development ("SD2"" project)
- operation of the South Caucasus Pipeline ("SCP" project) and its expansion ("SCPX" project),
- construction of the Trans-Anatolian Natural Gas Pipeline ("TANAP" project) and
- construction of the Trans Adriatic Pipeline ("TAP" project) (SD2, SCPX, TANAP and TAP collectively, the "Projects").

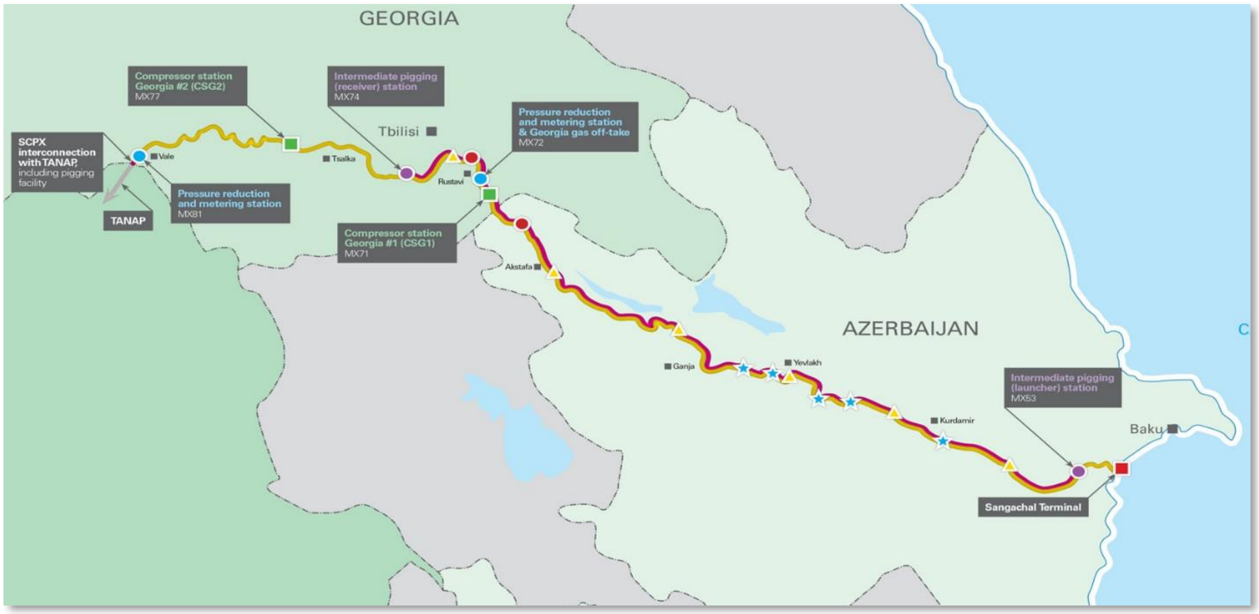
Upon completion, the SD2 project will add a further 16bcm of natural gas per annum to 10.9bcma (maximum production capacity) already produced under SD1 project. Total length of the newly constructed SCPX, TANAP and TAP pipelines will be more than 3200 km.

Exhibit E-5 Southern Gas Corridor map, by SCG

E.2.6 SCPX

SCPX (South Caucasus Pipeline Expansion) is a natural gas pipeline from the Shah Deniz gas field in the Azerbaijan sector of the Caspian Sea to Turkey (Exhibit E-6). It runs parallel to SCP (South Caucasus Pipeline), built in the same corridor as Baku-Tbilisi-Ceyhan pipeline. SCP pipeline is owned by the South Caucasus Pipeline Company Limited. The annual transportation capacity is 7.41 bcma. The expansion includes construction of a new 48" pipeline looping SCP at Azerbaijani and Georgian territories as well as construction of two new compressor stations in Georgia. The new pipeline is approximately 489 km long (424 km in Azerbaijan, 63 km in Georgia and 2 km in TANAP interconnection). The new pipeline started operating on 30 June 2018. Because of the expansion, SCP's throughput capacity is expected to reach approximately 23.4 bcma, which would triple the current overall transportation capacity of the system. SCP's capacity may be further expanded to 31 bcma, if needed. The pipeline has been linked to TANAP at the Georgian-Turkey border, thus enabling the transportation of natural gas further to Turkey and Europe.

Exhibit E-6 SCPX trunk line map



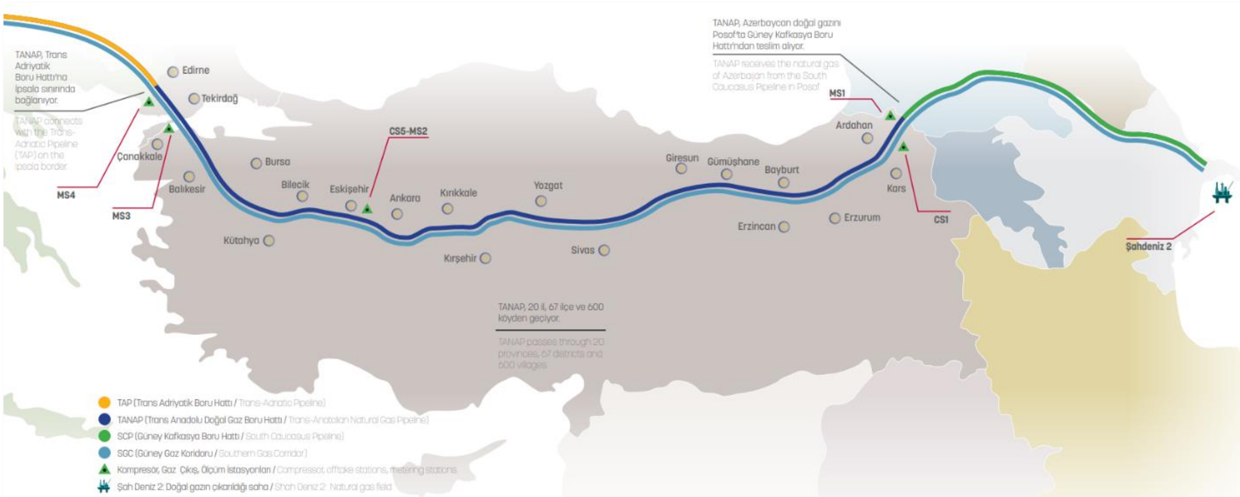
Source: SGC

E.2.7 TANAP

TANAP connects directly to SCP on the Georgia-Turkey border and will connect to TAP on the Turkey-Greece border. From this point, the TAP Pipeline will connect to convey natural gas to EU. Two off-take stations are located within Turkey for national natural gas transmission, one located in Eskisehir and the other in Thrace. With 19km running under the Sea of Marmara, the main pipeline within Turkey reach a total of 1850km, along with off-take stations and aboveground installations, with their numbers and properties detailed below:

- Seven (7) compressor stations
- Four (4) measuring stations,
- Eleven (11) pigging stations,
- 49 block valve stations and
- Two (2) off-take stations to supply Turkey's national natural gas network

Exhibit E-7 TANAP trunk map, by TANAP



Source: TANAP

E.2.8 TAP

TAP will connect directly to TANAP on the Turkish-Greek border and transport natural gas via Greece and Albania, across the Adriatic Sea to southern Italy. TAP is also expected to have "physical reverse flow" features, which will allow gas from Italy to be diverted to Southeast Europe, if required. The pipeline will be 878 km long and is expected to become operational in 2020. Initial transportation capacity will be 10 bcma, further to be expanded to 20 bcma

Exhibit E-8 TAP trunk line map

Source: TAP

E.2.9 Poseidon and EASTMED Pipelines

E.2.9.1 Poseidon

Poseidon Pipeline is a multi-source natural gas interconnector stretching from the Turkish-Greek border to Italy. With an Initial Capacity 15 bcma at the Greek-Turkish border and Expansion Capacity of up to 20 bcma, the Poseidon Pipeline links Greece with the Italian, the Bulgarian and the European gas system providing access to the gas infrastructure and sources available at Greece's Eastern borders, including via connections with the EastMed Pipeline and the IGB Pipeline projects. The Poseidon Pipeline will extend for approximately 760 km on Greek territory (the onshore section) from the Turkish-Greek border in Kipi to the landfall in Florovouni and for approximately 216 km crossing the Ionian Sea up to the landfall in Italy and the receiving terminal in Otranto (the offshore section), where it will be connected to the Italian national gas transport system. The project's new configuration will enable access to gas from the Caspian Basin, Central Asia, the Middle East and the Eastern Mediterranean Basin.

Exhibit E-9 Poseidon trunk map, by IGI Poseidon

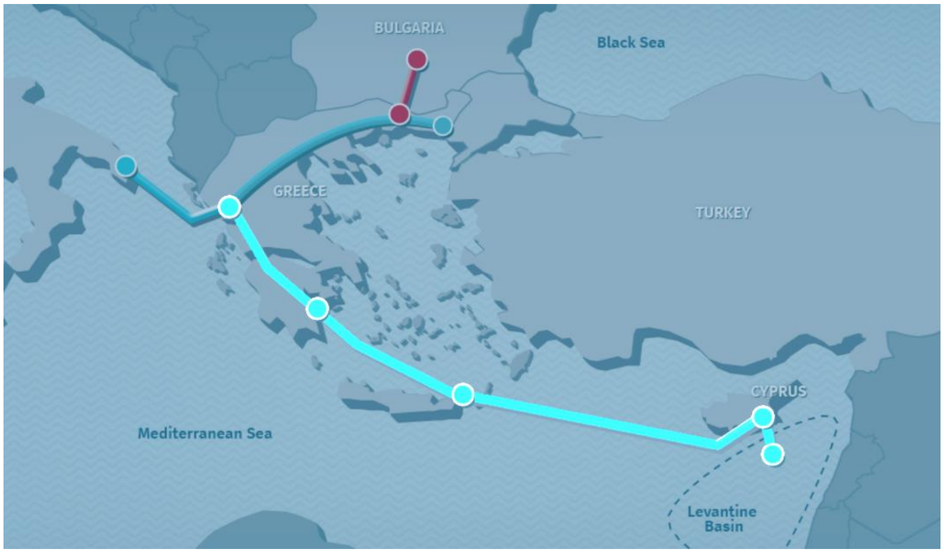
E.2.9.2 EASTMED

The Eastern Mediterranean (EastMed) pipeline project relates to an offshore/onshore natural gas pipeline, directly connecting East Mediterranean resources to Greece via Cyprus and Crete. The project is currently designed to transport initially 10 bcma from the off-shore gas reserves in the Levantine Basin (Cyprus and Israel) into Greece and, in conjunction with the Poseidon and IGB pipelines, int to Italy and other South East European countries. Furthermore, the pipeline would allow to feed Cyprus internal consumption with additional 1 bcma. The EastMed project current design foresees 1300 km offshore pipeline and a 600 km onshore pipeline. The EastMed pipeline is preliminarily designed to have exit points in Cyprus, Crete, mainland Greece as well as the connection point with the Poseidon pipeline. The pipeline starts from the new natural gas discoveries in the East Mediterranean region and comprises the following sections:

- 200 km offshore pipeline stretching from Eastern Mediterranean sources to Cyprus

- 700 km offshore pipeline connecting Cyprus to Crete Island
- 400 km offshore pipeline from Crete to mainland Greece (Peloponnese)
- 600 km onshore pipeline crossing Peloponnese and West Greece

Exhibit E-10 EASTMED trunk map, by IGI Poseidon

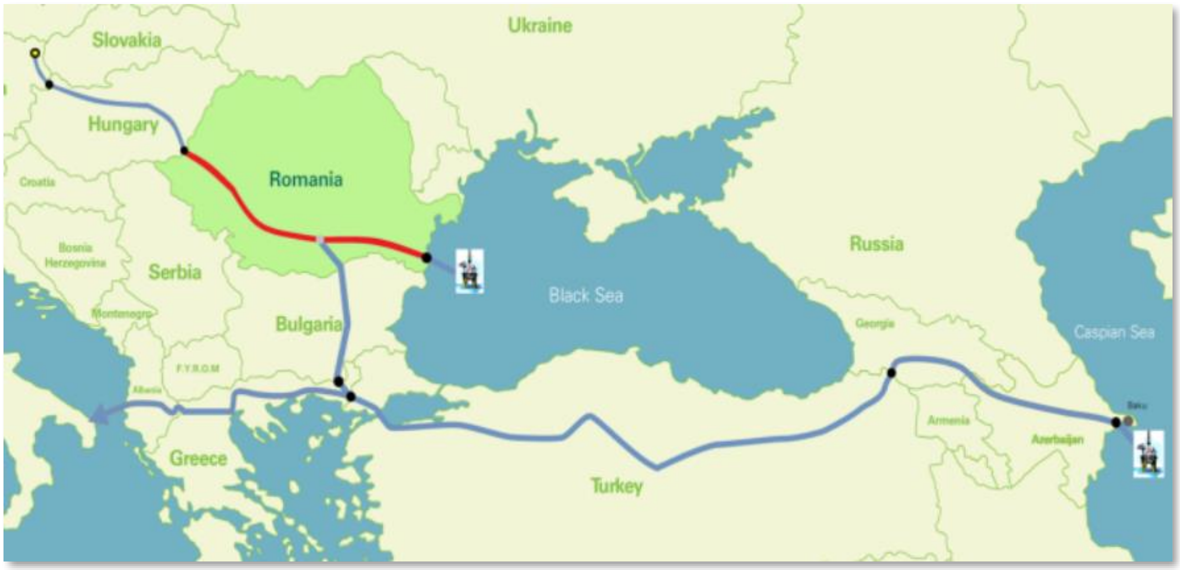


Source: IGI Poseidon

E.2.10 BRUA

BRUA (Bulgaria-Romania-Hungary-Austrian) makes part of Southern Gas Corridor connection. BRUAS is designed as reversed flow trunk that can supply Bulgaria or Hungary. The pipeline is 32" line about 528km long, will connect the existing Romanian transmission system with the Bulgarian Giurgiu interconnection point and Hungarian transmission systems at Csanadpalota. There are 3 CS foreseen along the pipeline route at Podisor, Bibesti and Jupa. In Bulgarian direction the pipeline will have 1.5 bcma capacity as in the Hungarian direction 1.7 bcma. Further there will be increase in the capacity towards Hungary to 4.4 bcma. The initial supply source will be the Romanian gas field sin Black Sea. BRUA will have connections to SC (TANAP/TAP) thru TAP-IGB.

Exhibit E-11 BRUA trunk line map



Note: BRUA pipeline section is shown in red

F. ALTERNATIVE FUEL GAS SOURCES

F.1 LNG

There are twenty-eight LNG terminals in Europe, all of them import terminals. Existing export terminals are in Norway and Russia. Twenty-four out twenty-eight terminals are in EU countries and four are in Turkey. Out of twenty-eight LNG terminals in Europe, twenty-three terminals are of onshore design, four terminals are floating storage and regasification units (FSRUs), and one terminal is Floating Storage Unit (FSU). Majority of terminals are in Western Europe. In SSE there is one operational in Greece, and two planned one in Greece and one in Croatia. As for SSE and Black Sea, there are no LNG terminals. Tukey has four terminals and none in Black Sea. To date the figures shows that available LNG infrastructure in Europe is not 100% loaded.

As per the Moldova Energy Strategy until 2030, security of gas supply is one of the key state activities in energy sector. Considering that the natural gas is one of the key components in the country energy mix, reliability of gas supply becomes matter of national security. Gas supply for Moldova could be ranked as a critical task bearing in mind that Moldova secures supplies from a single source, and that it lacks in-country natural gas resources. The issue's importance is increasing especially in the context of the Russian gas transiting thru Ukraine. One of the country's main objectives is to ensure the security of natural gas supply and this includes diversification of supply sources and routes. To date, Moldova imports almost 100% of its natural gas, about 3 bcma in total, from Russia through Ukraine, and the existing supply contract is due to expire in 2019. The following solutions are being considered to ensure the future secured gas supplies to Moldova:

- Ungheni – Chisinau gas pipeline, total capacity of 1.5 bcma, expected project completion by the beginning of 2020
- Reverse flow on the Trans-Balkan pipelines corridor: required reverse capacity of 3.2 bcma, on the existing 7.3 bcma pipeline.

The SSE Countries efforts to diversify the natural gas, pushes development of the regional the gas infrastructure as discussed above. This will most probably make Moldova part of the LNG market.

F.1.1 Current Situation – LNG in Moldova

LNG supply to Moldova is a potential alternative to natural gas. The closest to Moldova existing LNG infrastructure is in Greece (Revithoussa) and Turkey (Aliaga, Marmara Egiglisi). There are plans for new LNG facilities in Greece (Alexandroupolis), Romania (Constanta), Ukraine (Yuzhni), where the most advanced in project development is Alexandroupolis. Gastrade, the project owner, successfully closed the market test for the project.

Recent (2019) LNG supply was executed to Bulgaria via Revithoussa, and Sidikastro (Greece)-Kulata (Bulgaria) interconnection. The operation is prominent that such an activity could be executed to Moldova via Greece-Bulgaria-Romania-Moldova interconnections.

F.1.2 Revithoussa LNG Terminal

Revithoussa LNG terminal, owned DESFA, is an important energy asset for Greece, providing security of energy supply, operational flexibility in the transmission system and increased capability to meet peak gas demand. The terminal is one of the 13 LNG terminals that operate in the Mediterranean region and in Europe. The terminal is located on the islet of Revithoussa, in the gulf of Pahi at Megara, 45 km west of Athens. For 18 years operation, more than 300 LNG cargoes were received and temporarily stored in the 2 tanks with capacity of 130,000 m^3. LNG is gasified by the cryogenic equipment of the installation and delivered to the Greece natural gas transmission system in Agia Triada. In 2018 the total storage capacity was increased to 225,000 m^3. Re-gasification rate was also increased from 1000m^3/h to 1400m^3/h. As mentioned above there were recent (2019) offloads of 2 cargoes in total of 140mcm in Revithoussa, which were re-gasified and transferred to Bulgaria via existing Bulgaria-Greece interconnection.

Exhibit F-1 Revithoussa LNG terminal location, by ENTSOG

F.1.3 ALIAGA LNG Terminals

There are two LNG terminals near Aliaga village, close to Izmir Turkey

- ETKI LNG Terminal is built and operated on sea shore of Aegean Sea at Aliaga-Izmir. Aliağa LNG terminal is a floating unit. Initial unit was SRV vessel MT GDF Suez Neptune capable of storing 145,000 m³, re-gasifying LNG delivered from other ships. Presently moored in 2019, vessel is FSRU TURQUOISE P with capacity of 166,631 m³ and regasification capacity of 21 cmd.
- EgeGaz Aliağa LNG Terminal is built on EgeGaz own land on sea shore of Aegean Sea at Aliaga-Izmir. Besides the regasification and send out capability, Terminal can also load LNG on trucks. Technical Specifications of the Terminal is as follows:

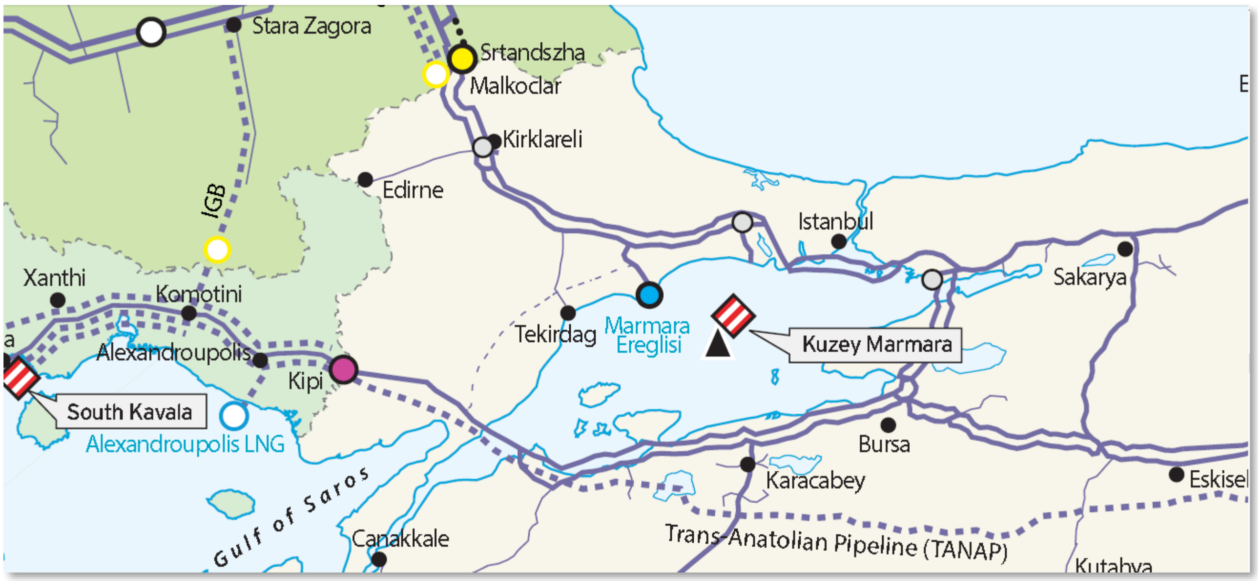
  - Two full containment LNG tanks each 140 000 m³,
  - Regasification and send-out capacity: 1660000 Sm³/h,
  - Jetty: LNG vessels up to Q-max; unloading capacity of 11000 m³/h,

Exhibit F-2 Aliaga LNG Terminal location, by ENTSOG

F.1.4 Marmara Ereglisi LNG Terminal

In 1994, BOTAS put in operation Marmara Ereglisi LNG Terminal. The terminal has a 37 mcmd gasification capacity and 3 storage tankers, 85,000 m³ capacity each. Marmara Ereglisi LNG Facility is an above-ground LNG facility in Tekirdag Province, Turkey. The LNG terminal is operated by the state-owned natural gas company BOTAS. The terminal accepts the offload of LNG carriers and stores the LNG in tanks and re-gasified to convey to the main pipeline system as needed. The construction started in 1984 and facility went into service in 1994. In 2007, 6 filling platforms were added for tank trucks having 20–50 m3 capacity. Three filling platforms can fill up daily 75 tanker trucks.

Exhibit F-3 Marmara Ereglisi LNG Terminal location, by ENTSOG



F.1.5 Alexandroupolis LNG Terminal

Alexandroupolis LNG is planned to be INGS comprising of offshore floating unit, reception, storage and re-gasification and subsea transmission system connecting to national gas network. The floating unit is to be moored at distance of 17.6 km SW from the port of Alexandroupolis and 10 km from the nearest opposite shore of Makri village. The Alexandroupolis INGS will have capacity of 700000 m^3/h or 6.1 bcma and a storage capacity of up to 170,000 m^3. Commercial operation is expected to start in 2022. The project will have direct access to the Bulgarian market via the planned Greek-Bulgarian Interconnector pipeline (IGB) presently under construction. Or thru Bulgarian network to Romania, Serbian, and Hungary and other SSE countries. There are possibilities as well to get supply to Turkey via the Turkey-Greece interconnection pipeline. Another alternative is to supply gas to Western Balkans thru TAP. In 2018 Bulgaria announced its intentions to participate in the project with about 25% stake share in the project.

Exhibit F-4 Alexandroupolis LNG location, by ENTSOG

F.1.6 LNG Over and Above Bosporus

At present day there is no LNG terminal in Black Sea, neither export nor import. Romania and Ukraine both have plans to build LNG terminals:

- Ukraine at Odessa (FSRU)
- Romania at Constanta (onshore)

The major issue is LNG tanker passage thru Istanbul Strait (Bosporus). Bosporus is one the most complex straits to navigate a large ship like an LNG tanker, the heavy ship traffic adds additional complexity. With nearly 43,000 vessels passing thru in 2017, the Strait sees nearly three times the traffic of the Suez Canal. Concerned of possible accident, and possible risk event with catoptric consequences, Turkey prohibited LNG tanker passages thru the strait. Thus, an alternative of LNG supply thru the Bosporus any Black Sea country is considered as negligible, since there is no reason for Turkey to change its position. However, with Turkey announcing construction of the Istanbul Canal Project, Turkey's position on transit of LNG tanks thru the straits might be reconsidered. Despite above, in 2012 Ukraine launched project for FSRU near Odesa. The project was put on hold in 2013, reassigned in 2017 and subsequently shelved.

Exhibit F-5 Yuzhnyi LNG terminal location, by ENTSOG

Romania, Azerbaijan and Georgia still consider the AGRI project. The project development started on 2010. Shareholders in the AGRI are SOCAR (Azerbaijan), GOGC (Georgia) and Romgaz (Romania), MVM (Hungary). Feasibility Study for the project was completed in 2014, the study provided 3 scenarios to consider for AGRI LNG development: 2 bcma for 1.2 BM€, 5 bcma at 2.8 BM€, and 8 bcma at 4.5 BM€. The project when delivered will be the first LNG in Black Sea, transporting gas from Caspian region to SSE diversifying the energy sources in the region. AGRI was considered as an integral part of the Southern Corridor, providing the shortest possible routing from Caspian fields to European market. Potential start-up date in 2026.

Exhibit F-6 Constanta LNG terminal location, by ENTSOG

F.2 BIO-GAS ALTERNATIVE

Bio-gas is an alternative to natural gas. Even considering that the concentration of methane in the final bio-gas product is lower than in natural gas (on average approximately 70%), it still presents an alternative. Bio gas is the product of anaerobic digestion of organic matters, or fermentation of biodegradable matter. It can be produced from raw materials such as agricultural waste, manure, municipal waste, plant material, sewage, green waste or food waste and any other organic matter. However, the methane content in the biogas varies depending on the raw materials used for production. Biogas is considered as renewable energy source and thus its production is subsidized. The power produced by biogas transformation is purchased at preferred tariffs.

Bio gas can be used in power generation equipment dedicated for bio-gas use. However due to the volumes of bio-gas usually produced, and storage capacities, the output of equipment is small. The major issue with the bio-gas is that it is considered a sour gas, due to the large volumes of CO_2, SOx, which with moisture present in the gas cause corrosion of the equipment and pipelines. Bio-gas can be injected in the existing natural gas infrastructure to levels not exceeding 3 vol% concentration or it will induce corrosion. Another issue with production and uses of biogas is its odor, which requires the sites that manufacture and use the bio-gas to be located away from the populated areas. Considering these issues, the bio-gas production should be located near the centers of its consumption.

The Moldova potential for biogas is estimated at 134MW of installed capacity equivalent to 805 GWh/yr. These figures represent 20% of the annual country energy demand. Power that can be generated is limited by availability of raw materials for biogas production. To date, in Moldova there are 5 biogas cogeneration stations with overall installed capacity of 5.6 MWe. Moldova promotes the use of biogas as a renewable energy source, implementing legislative measures and mechanism like: power purchasing guarantees; TSO purchases the power generated by plants with installed capacity large 10kW; facilitating licensing and permitting.

G. RISK MATRIX (SELECTION)

	Risk Category	Risk	Risk Description	Risk Consequences	Risk Mitigation	Risk Allocation	
						Public Partner	Shared Risk
Location risk - all the events that occur in the public-private partnership projects related to the property/lease right of the areas necessary for the project to be carried out, the location and the conditions of the location of the public-private partnership object that can lead to the impossibility of the development, the completion of the works within terms set out at initially estimated costs							
1.	Location Risk	Location Availability	Encountering difficulties regarding access to a particular location	Generates delays in the implementation stages of the project and further increases in project costs	The obligation of the public partner as at any stage of development of the public-private partnership project to ensure the access of the bidders to the location of the public-private partnership project	✓	

	Risk Category	Risk	Risk Description	Risk Consequences	Risk Mitigation	Risk Allocation	
						Public Partner	Shared Risk
2.		Unforeseen location or ground conditions	Temporary cessation of land use for the project activities, due to the discovery of archaeological remains and/ or national heritage, natural resources, groundwater	The increase of the time duration and of the costs regarding the project execution, the risk of stopping or cancelling the project	The public partner will ensure through geological research that the location chosen for the development of the project allows its implementation and does not contravene with the public interests of exploiting natural resources. At the same time, in the design phase, the private partner will check the geological expertise and ensure that it allows the development of the project. In case of finding unforeseen conditions of that cannot be alleviated the location destined for the development of the public-private partnership project will be changed		✓
3.		Approval of the necessary documents	Delays in obtaining the necessary approvals/ authorizations in the terms provided, or can be obtained subject to unpredictable conditions	Delays in the implementation stages of the project and further increases in project costs	Organizing an efficient framework of cooperation between both partners in the process of obtaining the necessary documentation regarding the development of the project, respecting terms stipulated in the contract		✓

	Risk Category	Risk	Risk Description	Risk Consequences	Risk Mitigation	Risk Allocation	
						Public Partner	Shared Risk
4.		Property title (claims)	Difficulties in the land acquisition process from the owners and/or obtaining the right to use the land	Increasing the time period for project implementation and increasing project costs	The private partner has the obligation to strictly check the documents of origin (cadastral registers) eliminating all the unclear		✓
Design and construction risk - all events within public-private partnership projects arising from improper design and construction and/or from engineering errors with impact on the cost of the project starting with the design, construction and operation stage							
5.	Design and construction risk	The discovery of archaeological remains	The discovery of archaeological remains and/or national heritage on a site that prevents construction work causing delays and increasing project costs	Increased costs and time required to implement the project	Maximum attention will be drawn in the geological investigation phase of the ground. Subsequently, if such discoveries during the construction phase, the private partner will immediately notify the public partner who will evaluate vestiges. The risk will be managed by the public partner.	✓	
Financing risk - all events within the public-private partnership projects with impact on the capital invested or borrowed by the private partner for the development of the project							

	Risk Category	Risk	Risk Description	Risk Consequences	Risk Mitigation	Risk Allocation	
						Public Partner	Shared Risk
6.	Financing risk	Increase of the costs of the initial investment	Due to changes in legislation, policy or of other nature, the initial investment becomes greater than estimated by the private partner, or the private partner can no longer provide the investment, additional financing is required	Increasing project costs or stopping the project	The guarantee by the private partner of the completion of the initial investment through a bank guarantee of good execution. Also, the public partner can cover part of the investment need through subsidies		✓

Political/legislative risk - all events within the public-private partnership projects generated by possible legislative changes and/or the policy of the public partner

	Risk Category	Risk	Risk Description	Risk Consequences	Risk Mitigation	Risk Allocation	
						Public Partner	Shared Risk
7.	Political/legislative risk	Change of field-specific legislation	The risk of legislative changes and the policy of the public authority that cannot be anticipated at the signing of the contract and which are addressed directly, specifically and exclusively to the project, leading to additional capital or operational costs for the private partner	Affecting the profitability of the project and the premature conclusion of the contract	The public partner will ensure the continuity of the policies for the development of the public-private partnership projects including the fiscal policies related to the public infrastructure	✓	
8.		Withdrawal of complementary support	Changes in the strategy, tactics and current actions of the political factors in their own country (at national, regional and local level), from the countries with which the company has direct and indirect contracts	Affecting the profitability of the project and the premature conclusion of the contract	The public partner will contribute to the good development of the project within the contractual limits	✓	

	Risk Category	Risk	Risk Description	Risk Consequences	Risk Mitigation	Risk Allocation	
						Public Partner	Shared Risk
Environmental risk - all the events within the public-private partnership projects with environmental impact that lead to the increase of the project cost by undertaking the measures for their elimination and their significant reduction							
9.	Environmental risk	Adjacent properties unavailable for project implementation	The emergence of buildings or other types of property adjacent to the public-private partnership object that do not allow the development of the project due to environmental contamination	The appearance of decontamination costs leading to the increase of the costs of carrying out the project under environmental conditions	Depending on the nature and cost of decontamination, the public partner can take on some of this risk generated on the properties made available to the project, controlling the process of monitoring the environmental pollution.	✓	
Force majeure - the totality of the unpredictable events within the public-private partnership projects caused by nature phenomena: earthquake, landslide, fire, drought, strong wind, torrential rain, flood, frost, snowfall etc. or social circumstances: revolution, belligerent state, blockade, strike, state ban on import or export, epidemic							

	Risk Category	Risk	Risk Description	Risk Consequences	Risk Mitigation	Risk Allocation	
						Public Partner	Shared Risk
10.	Force majeure	Force majeure events	Inability to develop the public-private partnership project due to force majeure events	Complete destruction or deterioration of assets related to the public-private partnership project. Loss or deterioration of the assets of the public-private partnership project or of the service (inability to provide services), loss of the possibility of or delay in obtaining revenues	The private partner will take measures to insure the assets and/or will seek their repair or replacement as soon as possible. The private partner will be exempt from the consequences on the service, if the consequences are non-quantifiable, the private partner can establish financing reserves, the private partner must urgently identify an alternative regarding the provision of services, if the consequences are insured		✓

Source: Annex to Order No.143 of 2 August 2013 of the Ministry of Economy

H. NEW CAPACITIES TENDERING PROCEDURES

Tenders for the construction of new capacities or for increasing existing power generation capacities

For a better understanding of the regulatory context, we translated (and adapted for further clarity - see italic format) the most relevant aspects of the governmental draft on Regulations that applies to Tenders for the new capacities construction or for increasing the existing power generation capacities:

(...) The Government is in charge with the following tasks:

- *Establishes the type of auction;*
- *Establishes the subject of the auction, including the type of new capacity development projects (construction of a new power plant, capacity increase of an existing power plant, construction of new electrical capacities due to the reconstruction and refurbishment of an existing thermal power station in the district heating plant/ district heating plants);*
- *Establishes the size of the project, the location of the power plant and the type of production technology to be used.*

(...) The Central specialized body shall fulfill the following tasks:

- *Analyzes, (...) the situation created on the domestic electricity market and proposes to the Government the draft decision on the organization of the tender for the development of new production capacities;*
- *Develops the tender documentation, including the participation notice;*

(...) The Auction Commission carries out the following tasks:

- *Initiates and organizes the tender procedure;*
- *Prepares and presents to the Government the materials on the results of the tenders.*

When assessing the need to organize the auction, the Central specialized body will:

1) *Analyze*
    a. *the medium and long-term forecast of energy demand and supply;*
    b. *the existing domestic electricity market and the prospects for its development;*
2) *Determine the level of new production capacities needed to be built to ensure the security of electricity supply, taking into account the existing and planned capacities to be developed (including capacities authorized by the Government in accordance with Article 20 of Law No. 107/2016 on electricity and capacities to be developed in the context of the implementation of the support scheme established by the Law No 10/2016 on the promotion of the use of electricity from renewable sources);*
3) *Examine*
    a. *The existing situation and availability of primary energy resources in the country and from the import that can be used by new generation capacities;*
    b. *The types of technology used;*
    c. *The location of new power plants;*
    d. *The environmental impact of new production capacities to be developed;*
4) *Examine and identify the optimal options for the development of new production capacities (construction of new power plants, increase of existing power plants capacity, reconstruction / refurbishment of existing thermal power plants in district heating plants);*

5) *Estimate the costs necessary to build new production capacities and identifies the possible sources of financing (state budget sources, funds obtained from international lending institutions, funds obtained from external partners and donors, private investments or public-private partnerships, etc.) establishing the methodology to award the contracts as well as the social impact of the new capacity development projects implementation;*

The Specification must include, without limitation, the following information:

(...) the type of production technology, the conditions imposed on the technological profile of the equipment, the capacity factor and the service duration;

(...) the specifications and technical characteristics of the production equipment (generators, turbines, boilers, motors, transformers, distribution devices, switches, separators, compensators, automation and protection systems, etc.) linked to the requirements for compliance and quality, performance and efficiency, environmental, operability and maintenance, safety in operation, warranty and post-warranty terms;

(...) location requirements and detailed information for the installation phase access and for the power plant operating access and, where appropriate, specific data on the location of the power plant (topography, geology, mechanics soil and seismology, hydrology, meteorology, traffic routes, etc.);

(...) requirements on fuel supply and fuel storage capacity needed in order to produce electricity;

Depending on the financing source, the level of economic operators' involvement and the ownership foreseen for the new production plants to be developed, the following types of contracts might be awarded within the framework of tenders organized in accordance with this Regulation:

a) Contract for the development of capacities, production and acquisition of electric power;

b) Contract for the construction of electricity generation capacities;

c) Contract based on public - private partnership.

The contract for the development of the new electricity plant, production and purchasing is a contract concluded between the entity designated by the Government and the tender winner for the final auction. The object will be the development of new production capacities (from the conceptual design of the project, financing, designing and procurement of equipment, construction) and production capacities operation / exploitation. This type of contract may be used in tenders organized in connection with the construction and operation by operators of new power plants if the successful tenderer intends to become an electricity producer operator following the construction.

The contract for the construction of electricity generation capacities is a contract concluded between the entity designated by the Government and the successful tenderer of the auction and implies the construction of the new production capacities. This type of contract is awarded if economic operators only provide design of new production capacities, procurement (including delivery) of necessary equipment, execution of construction and assembly works and put in function the new production capacities. In this case, the respective economic agent neither finance the project, nor owns or operates the new production facilities.

The Public-Private Partnership Contract is a contract concluded with the successful tenderer aiming to create a public-private partnership for the allocation of infrastructure assets, resources, bonds, risks and responsibilities associated with the development projects of the new power generation capacities, observing the requirements established by the Law no. 179/2008 on public-private partnership.

(...) The technical capacity test demonstrates the existence of a minimum technical endowment of the machinery, equipment, special technique, etc., in accordance with the requirements set out in the Tender Specifications, deemed necessary for the performance of the contract awarded following the tender.

The existence of technical endowment is demonstrated by the economic operator through the fixed assets documentation presented, copies of its rental / commodity contracts.

The technical proposal shall be structured by the bidder so that it provides all the necessary information and demonstrates its compliance with the technical requirements set out in the Tender Specifications. The technical proposal must contain at minimum the following information and documents:

1. *The description and general characteristics of the proposed project (structure, size, technology used, installed power, capacity factor, efficiency, duration, etc.);*
2. *The specifications and technical characteristics of the key power generation equipment (name, type of equipment, manufacturer, year of manufacture, compliance with technical requirements, compliance and quality, efficiency and environmental requirements, with industry standards, as well as the normative and technical documents, indicated in the Tender Specifications), as well as the procurement plan for this equipment. This plan must demonstrate the existence of a commitment or option agreed with the manufacturers or suppliers with regard to the acquisition and / or delivery of the key equipment within a timeframe that allows the construction to be completed within the terms set out in the Tender Book tasks (including procurement contracts, guarantees, letters of interest, etc.);*
3. *The impact of new production capacities on the environment, which must not exceed the emission levels set out in the Tender Specifications. The environmental impact is demonstrated by presenting the respective emission data / calculations resulting from the operation of the respective production capacities separately for each type of emission as well as in full, set in common units such as gram per kilowatt hour (g / kWh);*
4. *The location of new production capacities, the eligibility of land for the location of the new power plant or for increasing the existing power plant capacity and access to the existing infrastructure. The bidder demonstrates eligibility of the land by presenting the following information and documents, as appropriate:*

   a) Presentation and description of the location plan in the respective area;

   b) Information describing access to water, sewerage, railways and access roads (both public and private roads);

   c) Presentation of the list of land/ parcels required for the location, the documents proving the proof of ownership or use on the land/ parcels, including the extracts from the Register of immovable property and, as the case may be, the proof of the change of the destination of the agricultural land and/ or the file on the change of the land use category, drawn up in accordance with the Regulation on the mode of transmission, destination change and land exchange, approved by the Government Decision no. 1170/2016;

5. *The basic and reserve fuel supply plan used to produce electricity to ensure the viability and reliability of fuel supply. The viability and reliability of fuel supply is demonstrated by the submission of contracts, warranties, letters of interest from producers or suppliers of fuel to ensure the long-term purchase of fuel, the existence or development of sufficient capacity for fuel storage in order to ensure operational activity, as well as reserve fuel, etc.*
6. *The electrical network connection plan demonstrating the viability of the new power plant or of the existing power plant with increased capacity. The network connection notice should be attached, issued by the system operator. In case of lack of capacity in the network, should be attached the extract from the latest electricity grid development plan and confirmation by the system operator that the respective grid is to be developed or its existing capacity is to be increased within the time frame foreseen for the construction of the new production capacities.*