Armenia Power Sector Policy Note

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Artur Kochnakyan

Brendan Larkin-Connolly

Denzel Hankinson

Ani Balabanyan

Matteo Morgandi

Anne Olivier

Armenia Power Sector Policy Note

1818 H Street NW
Washington DC 20433
Telephone: 202-473-1000
Internet: www.worldbank.org

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Foreword

This presentation was prepared as part of the World Bank's Power Sector Policy Note for Armenia (the Note).

The objectives of the Note is to inform the Government's policy thinking by identifying the principal challenges that the power sector faces and outlining solutions for overcoming them. The Note also discusses some broader energy sector issues related to the gas tariff structure and demand.

The Note will also be disseminated to increase understanding and awareness among key stakeholders and the general public on the key challenges facing the power sector and the potential solutions for overcoming them. This will help to promote improved dialogue and collaboration between the Government and the other key stakeholders.

The Note was prepared based on the data generated by the relevant energy companies in Armenia, the Public Service Regulatory Commission, the World Bank internal data bases, and discussions with the Ministry of Energy and Natural Resources and Power System Operator.

Synopsis of Main Challenges and Solutions

Highest-cost and dilapidated Hrazdan TPP will need to run post 2016 to avoid supply gap because new lower cost CCGT cannot be realistically constructed earlier than 2020.

Several transmission assets are a threat to supply reliability. Many transmission lines and substations incur high outage rates, which could lead to system-wide failure.

Affordability is a growing concern. Climbing energy costs increased the share of household energy expenses to 10%. It will get worse as the much needed new investments are made.

Deterioration of governance and financial standing of state power companies. In recent years tariffs were frequently lagging cost-recovery, the financial management decisions were not always prudent, and a key generation asset was sold through a direct negotiated sale.

In order to address the above challenges the Government needs to:

Add new generation: Immediately focus public and private financial and implementation capacity on a new gas-fired generation unit of around 500 MW.

Revise tariff structure: Remove perverse tariff incentives that are accelerating winter electricity consumption and unnecessary gas consumption by public facilities and commercial establishments.

Rehabilitate key transmission assets: Rehabilitate key substation and transmission lines critical for system-wide reliability of power supply.

Implement financial recovery plan: Design and implement financial recovery plan for state-owned power companies, including consistent application of cost recovery tariffs.

Protect the poor: Top up social assistance program to make basic level of consumption affordable

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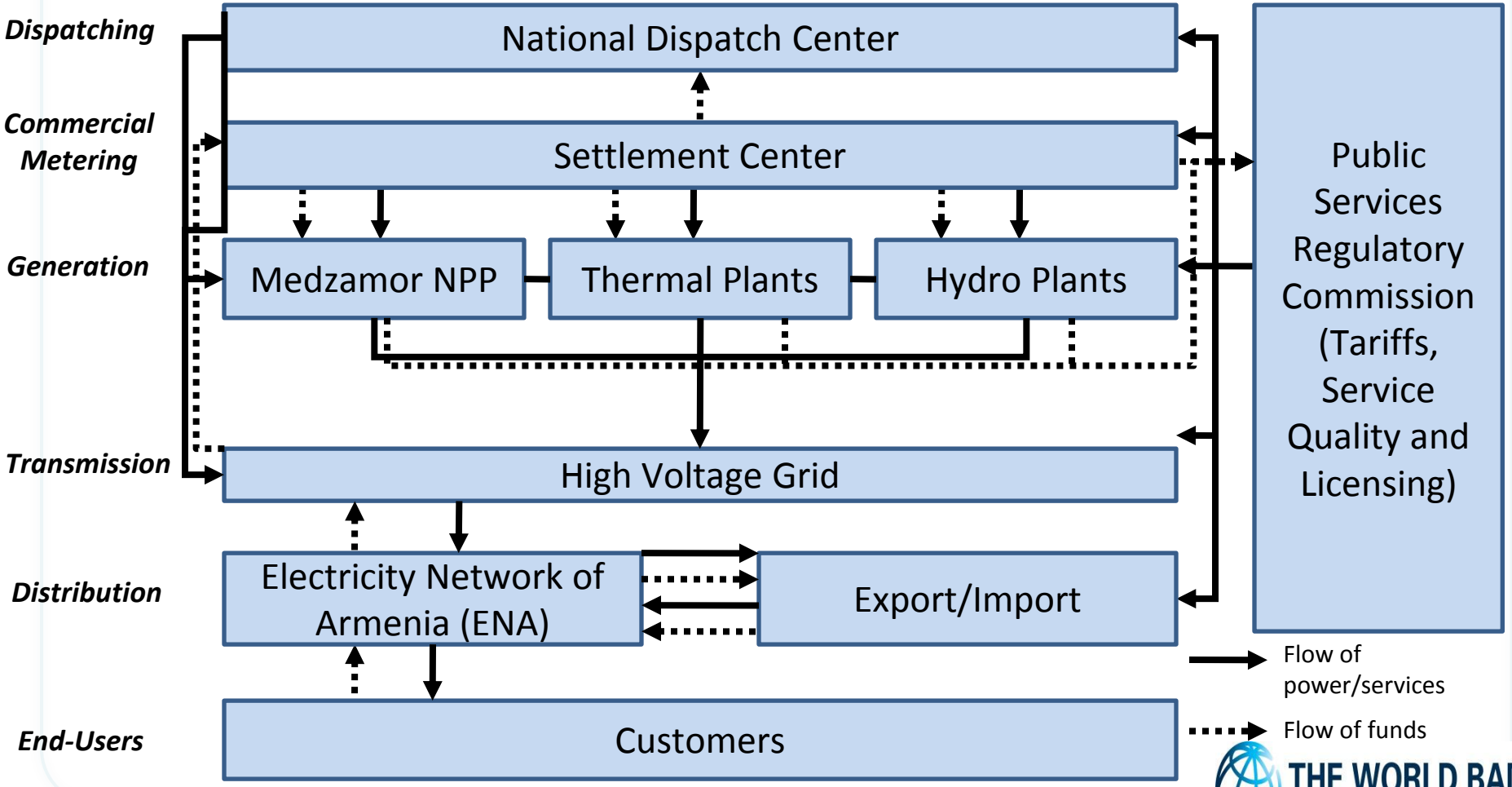
Overview: Power Sector Structure

- The sector is fully unbundled
- The sector is regulated by independent and competent regulator

- The distribution company is the single buyer
- The Ministry of Energy and Natural Resources develops and implements energy policy



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Supply Adequacy

Challenges

- Generation capacity to meet forecast electricity demand
- Suboptimal electricity and gas tariff structures

Solutions

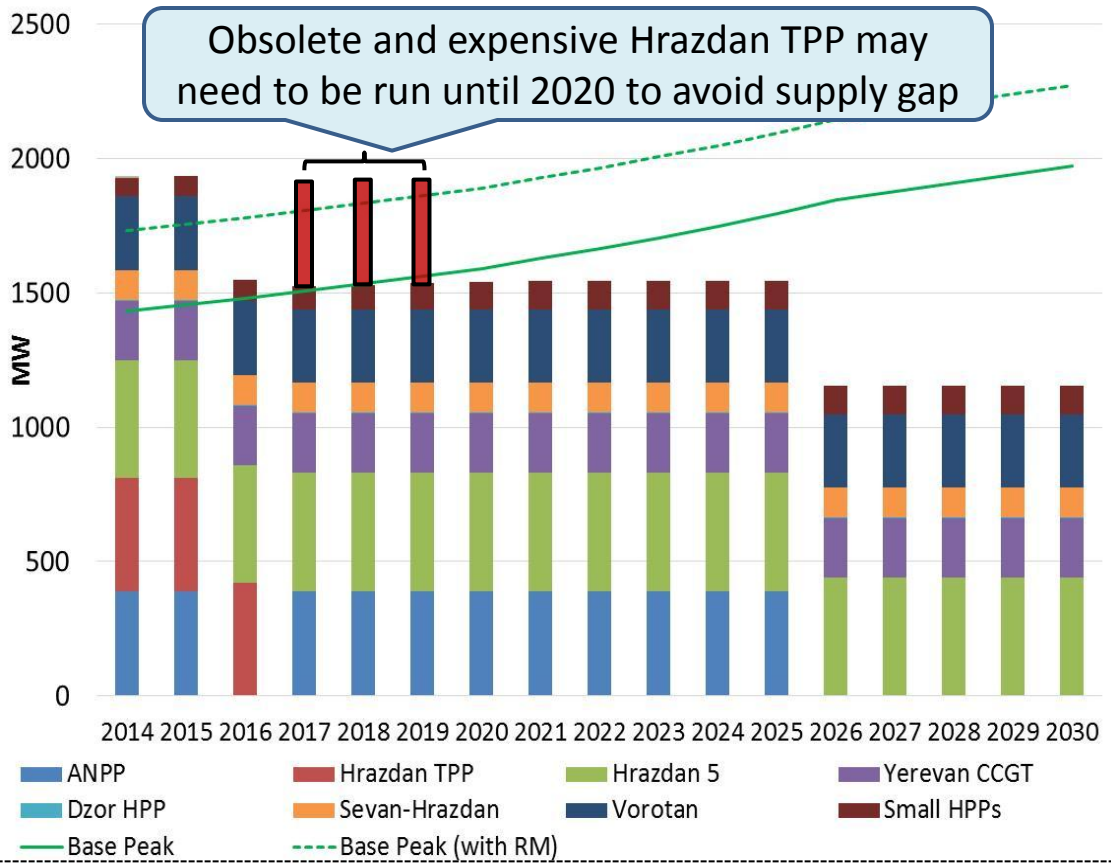
- Build new capacity
- Scale up energy efficiency
- Improve tariff structure

Key Next Steps

- **Financing options study, feasibility study and ESIA for a new Combined Cycle Gas Turbine station**
- **Develop Loriberd and Shnogh**
- **Study on energy efficiency potential**
- **Introduce marginal cost based tariffs**
- **Study on gas tariff structure**

Challenge #1: Supply Adequacy

To avoid supply gap, highest-cost Hrazdan TPP will need to run until new capacity is built



- All units of Hrazdan TPP will be past their operating lives by 2016
- Supply reliability may be jeopardized given disrepair and obsolescence of Hrazdan TPP
- Hrazdan TPP uses 40% more gas per 1 kWH compared to a new CCGT

Generation tariffs, VAT inclusive (AMD/kWh)

	2014
Hrazdan-5	40.1
Yerevan CCGT	34.9
Hrazdan TPP	**60.0**
Sevan-Hrazdan	8.6
Vorotan	9.4
ANPP	13.7
Small HPPs	25.3

Effective from August 1, 2014

- 550 MW Yerevan TPP is retired
- Only 50% of 800 MW Hrazdan TPP is available to meet winter peaks
- Only 45% of hydro capacity is available to meet winter peaks

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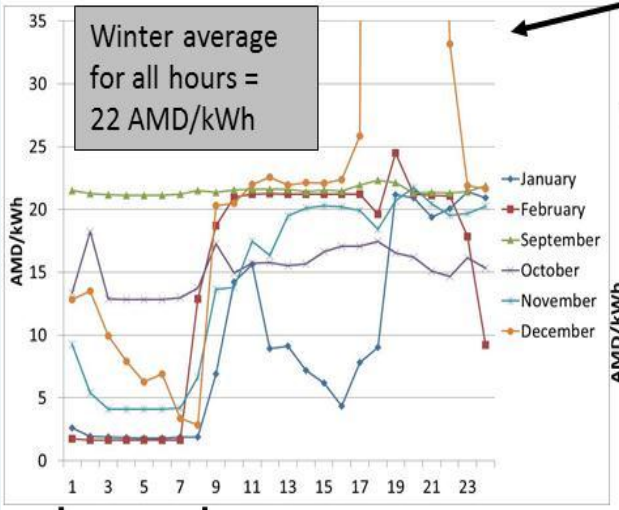
Challenge #1: Supply Adequacy

Current electricity tariff structure promotes over-consumption in winter, contributing to high peak

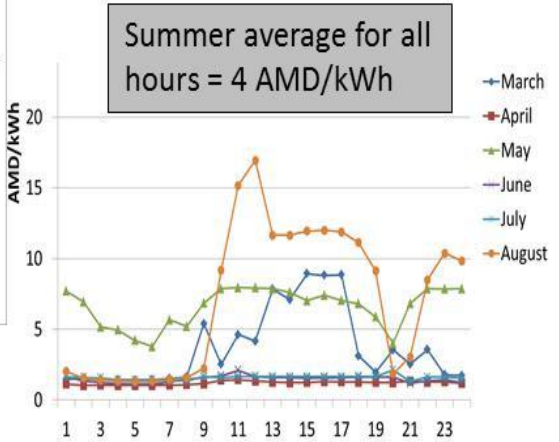
Deviations from Marginal Cost Based Pricing Principles:

Marginal costs in Armenia are highest in the winter

Typical Day Average Hourly Marginal Costs per kWh 2013-2017 (Sept - February)



Typical Day Average Hourly Marginal Costs per kWh 2013-2017 (March-August)



Lowest marginal costs occur from 12:01am – 8:00am

Seasonality. No seasonal tariff, although winter marginal costs are significantly higher than summer.

Time of use. Differential between peak and off-peak, or day and night, tariffs does not reflect the difference in the marginal cost of service.

Fixed charges. No fixed component in the monthly bill despite significant customer-related (and demand-related) costs of service, which are not driven by kWh consumed.

Voltage levels. Allocation of revenue requirement to different customer classes does not reflect differences in the marginal cost of serving different voltage levels.

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Challenge #1: Supply Adequacy

Current gas tariff structure promotes inefficient consumption

- Volume-based tariff encourages high consumption
  - Small volume consumers pay more (156 AMD/m^3) than large volume consumers (~ 114 AMD/m^3) for all units consumed
  - Perverse incentive for customers near the edge of the first block (hospitals, schools, SMEs) to over-consume to obtain the low wholesale price. Several public facilities are not interested in the WB/GEF Energy Efficiency Project given such tariff structure.
- Single-part tariff discourages utility from measures that reduce consumption (no fixed monthly charge and variable energy tariff)

Solutions: Supply Adequacy: Supply Plans Analyzed

A mix of nuclear, natural gas, and renewable energy supply plans were analyzed

Supply Plan	Summary
Gas	All capacity needs met by new gas plants
Gas + RE	Gas plants + 141 MW Loriberd and Shnogh HPPs by 2023 + 540 MW in PV, wind, geothermal by 2030
Large NPP	Large NPP (VVER-440) by 2026, with any additional capacity needs met by new gas plants
Large NPP + RE	Large NPP + 141 MW Loriberd and Shnogh HPPs by 2023 + 540 MW in PV, wind, geothermal by 2030

- VVER has net capacity of 1000 MW
- Renewable energy (RE) capacity is based on GoA targets for penetration of RE
- Under each scenario EE savings are assumed to grow by 5 MW per hour each year from 2015 to 2024, reaching 50 MW per hour in savings by 2024
- 260 MW of existing Small HPP capacity assumed for all scenarios

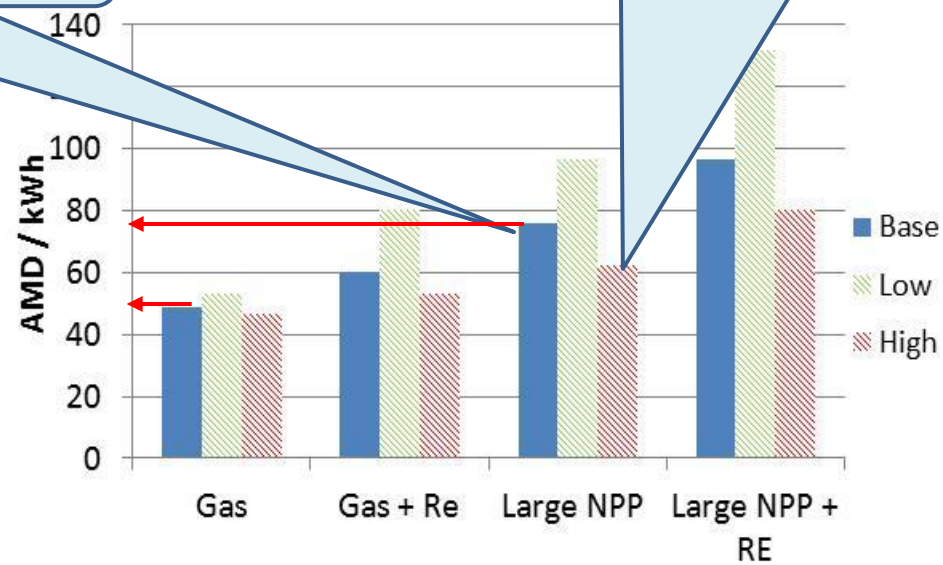
Solutions: Supply Adequacy: Least Cost Plan (LCP) And Demand Sensitivity

- **"Gas" is the LCP under the Base-case**
- **"Gas" remains the LCP under Low and High power demand scenarios**

"Large NPP" is more expensive under Base-case demand given high capital cost and over-capacity

"Large NPP" is less expensive under High-case demand

Supply Plan	Economic NPV (in Million US$)		
	Base Demand	Low Demand	High Demand
Gas	1,728	1,374	2,123
Gas + RE	2,500	2,297	2,793
Large NPP	3,341	3,015	3,639
Large NPP + RE	4,271	4,134	4,674



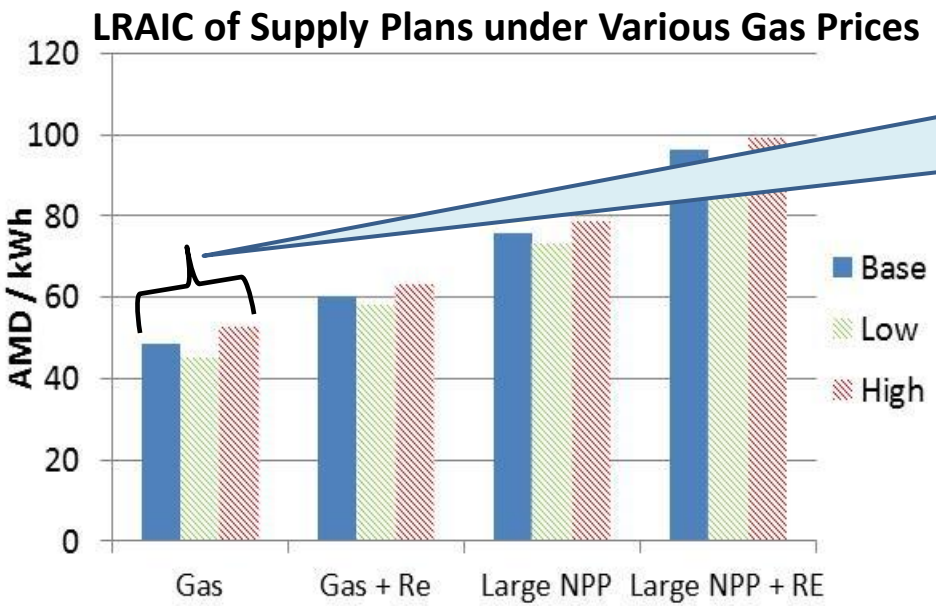
Long-Run Average Incremental Cost (LRAIC) by Demand Scenario

Supply plans with "RE" are more expensive given that most of the RE projects considered have high capital costs and low capacity factors

Base-case: Base-case power demand, base-case gas prices based on the formula for pricing of Russian gas imports , and current volume of swap with Iran

Solutions: Supply Adequacy: Sensitivity Analysis of LCP

"Gas" is the LCP even in case of High gas prices



LCP is more sensitive to gas price changes given that it is comprised of gas plants only. Other scenarios are less sensitive given RE and Large NPP

ΔP(imports) = 0.65 x ΔP(Orenburg price) + 0.35 x ΔUS-CPI

- Wholesale gas prices in Orenburg region* will have the largest impact on Armenian gas costs for power sector given the import gas pricing for Armenia

Real tariff (US$)		2014	2015	2016	2017	2018	2020	2022	2024	2026	2028	2030
Large consumers (Base-case)	$/tcm	239	241	249	258	268	287	308	331	353	370	387
Large consumers (High-case)	$/tcm	239	241	254	267	282	313	341	372	401	424	447
Large consumers (Low-case)	$/tcm	239	240	244	249	253	262	276	292	312	333	356

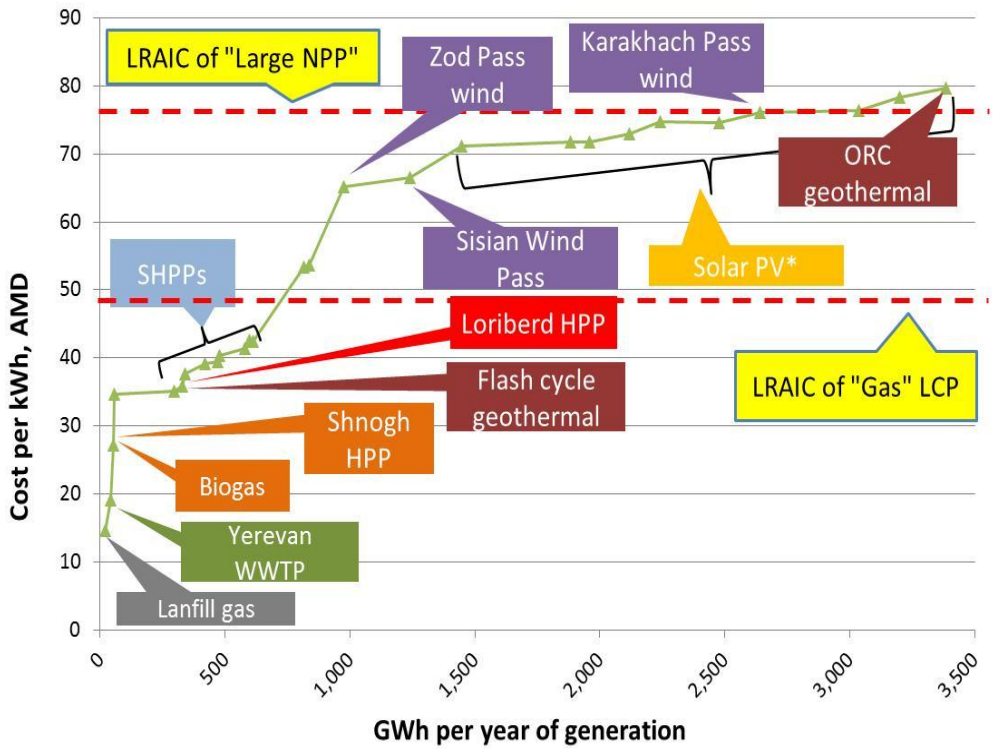
- Wholesale gas price scenarios are based on "Forecast of Social-Economic Development of Russia until 2030" released by Russia's Ministry of Economic Development;
- Current Gas Purchase Agreement with Russia is assumed to be extended post-2019 with the same pricing formula

Solutions: Supply Adequacy: Renewables

- **Shongh and Loriberd HPPs should be part of LCP**
- **Geothermal may be be part of LCP if >250° resource is found**

➢ Loriberd can be developed as peaking plant adding 66 MW of firm capacity
➢ Geothermal is low-cost base load unlike several other RE technologies

LEC of Renewable Energy

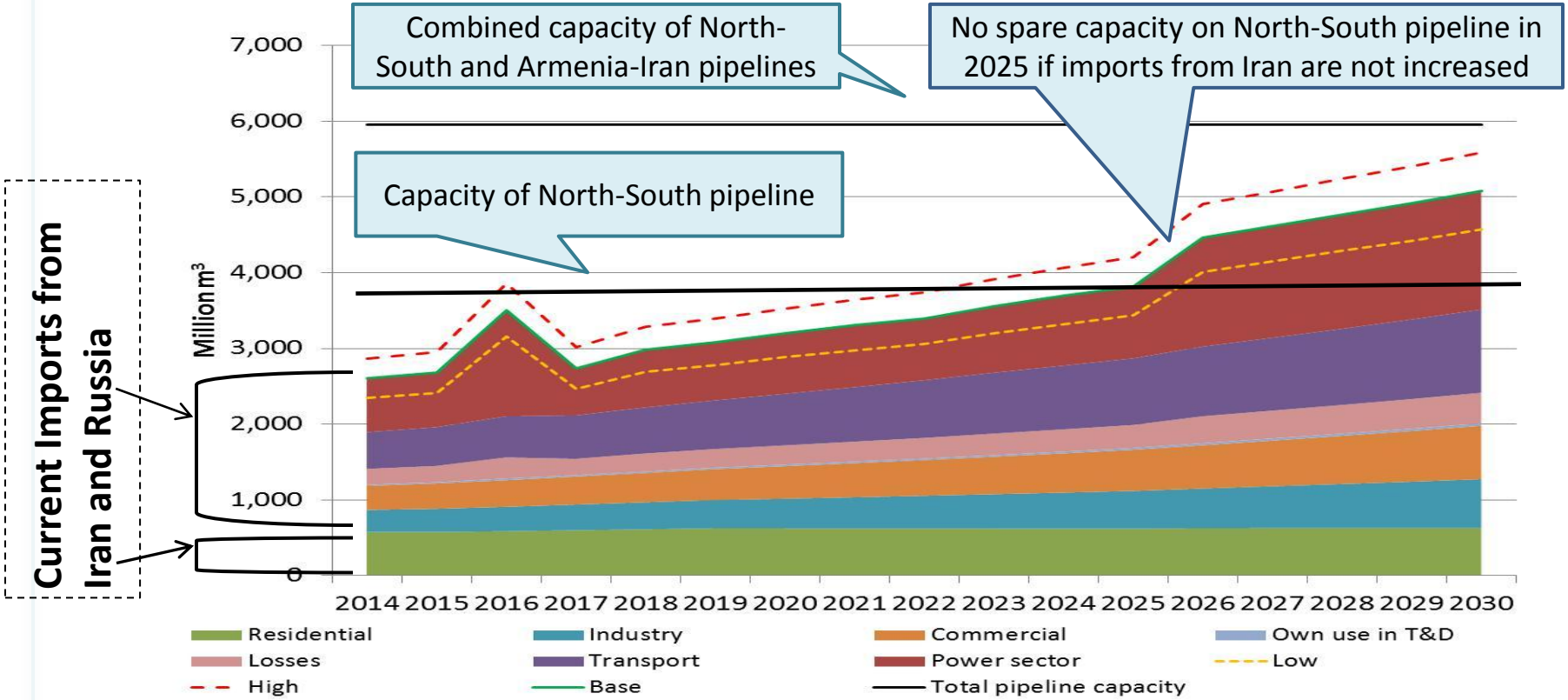


Technology	Unrealized potential (MW)	Generation (GWh/yr)
Distributed solar PV	1,300	1,800
Concentrating solar power (CSP)	1,200	2,400
Utility scale solar PV	830 – 1,200[a]	1,700 – 2,100[a]
Wind	300	650
Geothermal power*	at least 150	at least 1,100
Small hydropower	100	340
Shnogh HPP	75	300
Loriberd HPP	66	205
Biomass	30	230
Biogas	5	30
Landfill gas	2	20

* For 5 sites for which information is available

Solutions: Supply Adequacy: Gas Pipeline Capacity

- **Total pipeline capacity is sufficient to supply all of the gas required for LCP, however,**
- **LCP will be feasible only if Armenia imports more gas from Iran**

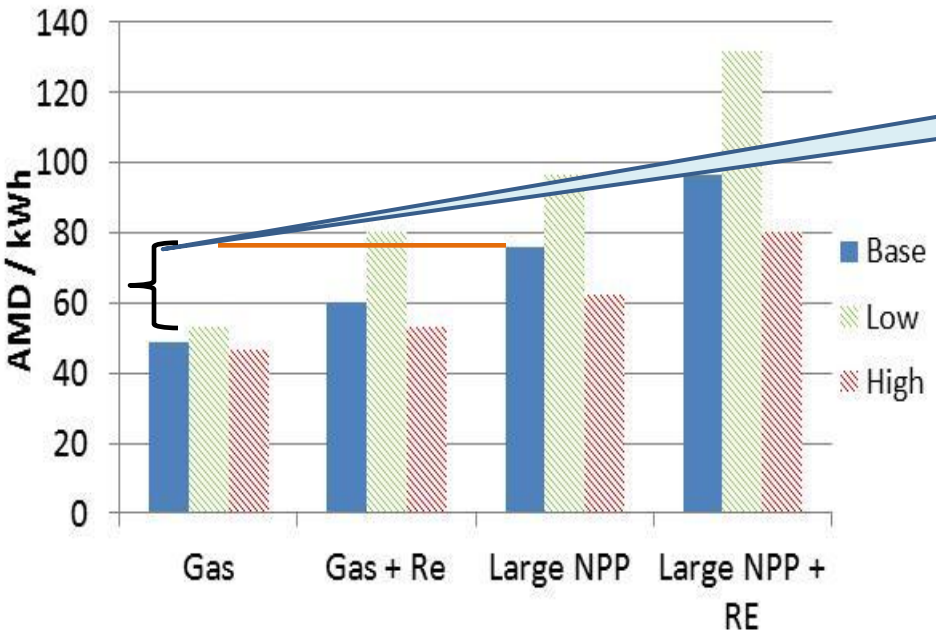


Currently Armenia receives only 0.4 bcm of gas from Iran under the swap deal whereas the capacity of the Iran-Armenia pipeline is 2.3 bcm/year

Solutions: Supply Adequacy: Nuclear Portfolios

Medium NPP may be a lower cost compared to Large NPP

Long-Run Average Incremental Cost by Demand Scenario



Medium NPP may have a cost between LCP and Large NPP

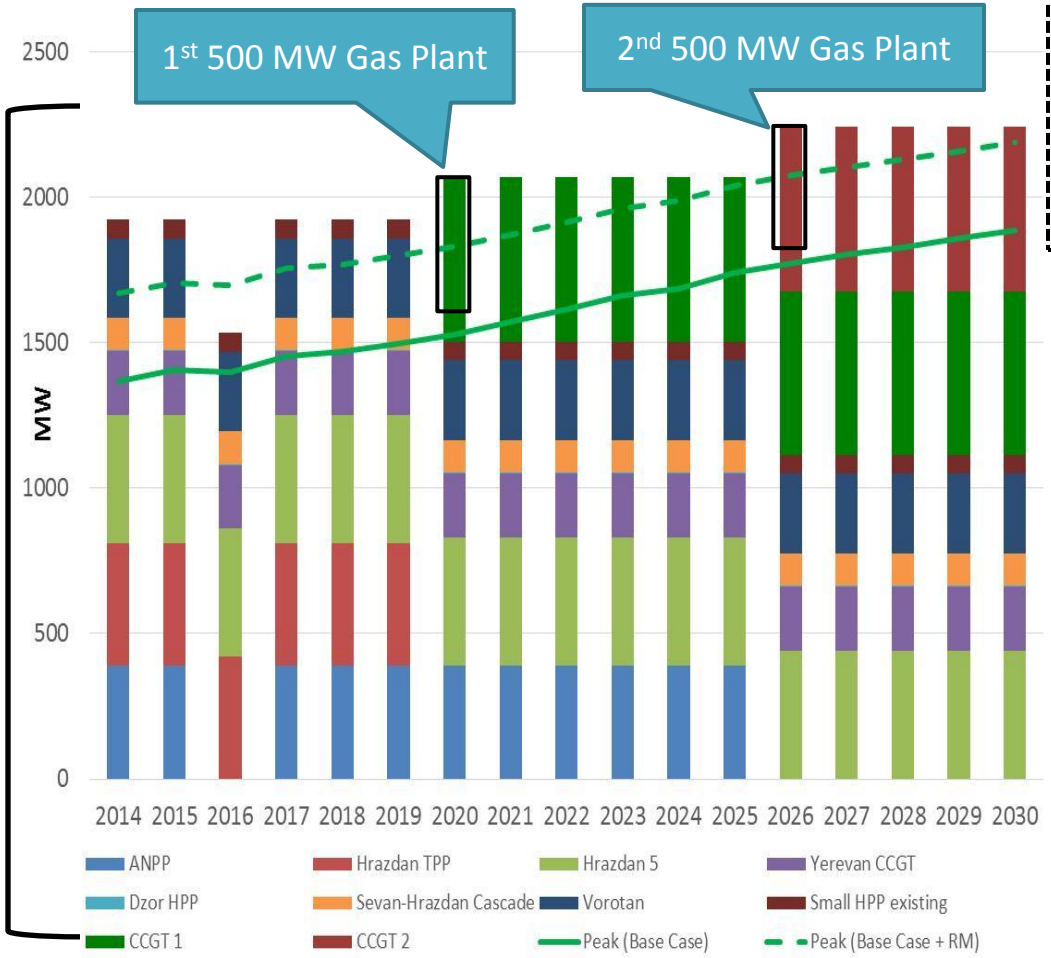
- Medium NPP may have small or no surplus capacity, thus, lower energy cost compared to Large NPP
- Medium NPP may have lower per kW capital cost. Even with the same per kW capital cost as Large NPP, it will still be lower cost due to smaller or no capacity surplus

Detailed feasibility study will be required to assess technical and economic viability of Medium NPP if the GoA decides to pursue it

Solutions: Supply Adequacy: New Plants Needed

- **Two new gas plants needed under LCP: 500 MW by 2020 and 500 MW by 2026**
- **One new plant is needed by 2020 under all other supply plans**

Capacity to meet Peak: LCP w/ Base Case Demand



Gas + RE: 345 MW plant by 2020
Large NPP: 500 MW plant by 2020
Large NPP + RE: 345 MW plant by 2020

Assumptions:

- ANPP off-line in 2016 for rehab, on-line again in 2017, retired in 2026
- Reserve margin (RM) = 300 MW
- Capacity factor of HPPs based on actual supply during 2013 peak

Solutions: Supply Adequacy: Construction of New CCGT

To commission a new gas-fired CCGT by 2020, the GoA needs to start the project now

For the new gas-fired CCGT to be on-line by 2020, the GoA will need to stick to below schedule:

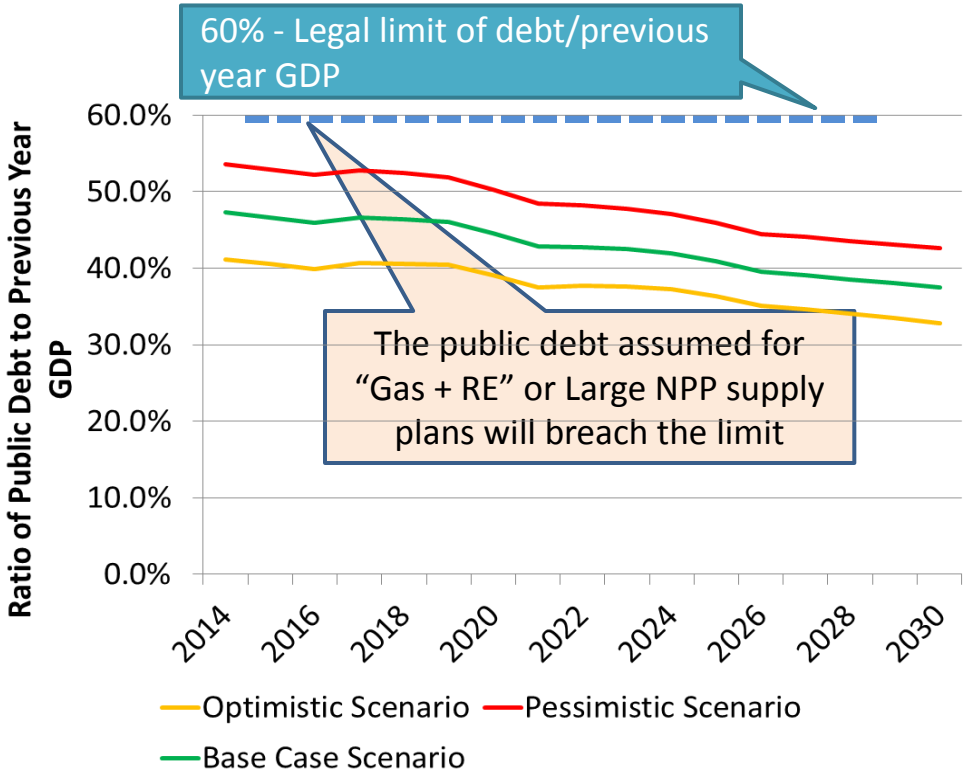
Key Steps	Duration	Schedule *
Decide on financing option	6 months	February 2015
Select a Consultant for a feasibility study, ESIA and preparation of bidding documents	7 months	March 2015
Complete the feasibility study and preparation of bidding documents	12 months	March 2016
Complete financial structuring and construction	44 months	November 2019
Test and commission the CCGT	2 months	January 2020

* The schedule assumes project preparation activities start in September 2014

Solutions: Supply Adequacy: Financing New Investments

LCP can be financed entirely with public debt, however…

- Entirely public financing is not a sustainable strategy given large needs in other sectors
- New CCGTs, Loriberd and Shnogh HPPs, and other RE are good candidates for PPPs



Supply Scenario	Capital cost (billion $)
Gas	1.2
Gas + RE	2.3
Large NPP	6.1
Large NPP + RE	7.3

All RE projects are planned as private and not included in calculation of public debt impact

Solutions: Supply Adequacy: Energy Efficiency

Energy efficiency can help meeting forecast power demand in a least-cost way

Key next steps :

- Conduct a comprehensive study to estimate economically and financially viable energy efficiency potential in the country. There are no reliable estimates of sectoral energy efficiency potential
- Adopt two-part seasonal and improved time-of-day electricity tariff structure
- Eliminate structural flaws in the gas tariff, which create a perverse incentive for some end-users to increase gas consumption to lower bills
- Mandate energy efficiency in new construction projects and all facility renovations programs financed by the Government and donors.
- Provide capital grants to the poor for energy efficiency retrofits

Actual energy savings achieved under WB/GEF project

Type of Facility	Energy Savings (%)	Payback period (years)
Schools	51-52%	6
Hospitals	51%	5
Street Lighting	45-53%	4-5
Other facilities	41%	5

Cost of electricity savings = AMD 19/kWh or 40% of unit cost under LCP

Solutions: Supply Adequacy: Improve Tariff Structure

Introduce marginal cost based electricity tariff to reduce the need for new supply

Two-part seasonal tariff with improved time-of-day bands may reduce peaks and need for new generation

Electricity

Two part tariff structure reflects the fact that many costs are not linked to kWh sold:

- **Per kWh tariff** reflects energy and capacity costs
- **Fixed monthly charge** reflects customer-related costs.
- Per kWh tariff differentiated by **season** and **time-of-use**

Per kWh charge is differentiated by season and time-of-use to better reflect how incremental costs are incurred:

- Winter Peak: 8:01 PM -12:00 AM, Sep – Feb
- Winter Off-peak: 12:01 AM - 8:00 AM, Sep- Feb
- Summer Peak: 8:01 PM - 12:00 AM, Mar - Aug
- Summer Off-peak: 12:01 AM - 8:00 AM, Mar – Aug

Gas

Conduct a study to determine:

- Marginal cost of supply to each category of consumers
- Allocate revenue requirement among classes according to marginal costs

Regional Trade: Short-Term

Limited regional connectivity and short-term trade opportunities

- One 220 kV and two 110 kV lines with Georgia allow for trading (up to 400 MW) in island operation. However, trading has decreased almost to zero in 2011-2013
- Two 220 kV lines with Iran allow for significant trading (around 400 MW). Trading primarily occurs under the electricity-for-gas swap deal

Export potential is limited in the short-term

- ➢ Excess short-term summer capacity and fully depreciated generation assets may make summer exports attractive, however,
- Exports to Turkey are not possible given unresolved political issues
- Georgia does not require energy in summer
- No relationship with Azerbaijan, which could have imported summer energy depending on its gas price policy for the energy sector
- Summer energy surplus in Armenia will significantly reduce as gas-for-electricity swap expands with Iran

	Short-term average costs (US$/kWh)*	Current export tariffs (US$/kWh)**
Armenia	0.056	No exports
Georgia	0.020	0.020-0.030***
Azerbaijan	0.030	0.040-0.045
Turkey	0.090	-
Iran	0.050	-

- ➢ In the short-term, winter exports are not feasible given:
- Expensive gas-fired generation cannot compete with thermal exports from Azerbaijan

Imports are not realistic given capacity balances in neighboring countries and political issues

* Bank team estimate; ** Platt's energy and national public sources; *** Such export tariffs are possible because summer HPP generation costs are below $0.01/kWh

Regional Trade: Long-Term

Limited long-term export opportunities

- In the long-term, summer and winter exports are not likely to be competitive because:
- No excess capacity at existing hydropower plants due to increase in domestic demand
- Absence of large low-cost untapped hydropower potential
- New gas or nuclear capacity is not likely to be cost-competitive for exports

	LRAIC (US$/kWh)*
Armenia	0.12-0.17
Georgia	0.07-0.08
Azerbaijan	0.04-0.13
Turkey	0.09-0.13
Iran	0.06-0.12

* Bank team estimates

Ongoing and planned regional interconnection projects:

- $140 million 400 kV line from Hrazdan TPP to Iran (2017). This 1000 MW line may be used to expand the swap, which is very beneficial for Armenia under current terms
- $150 million 400 kV line to Georgia (2020). The Government needs to carefully assess the economic rationale for the project because:
  - No power trade with Georgia even with existing 220 kV line
  - Limited opportunities for long-term power exports through Georgia:
    - Georgia has cheap hydropower surplus itself
    - Georgian transmission interconnections are not sufficient to wheel Armenian power
  - Transit of Georgian power to Iran through 400 kV line to Iran may be considered

Notes: The LRAICs will largely depend:
Georgia: Large HPPs developed and import prices of gas; Azerbaijan: Price of gas for the power sector; Iran: Price of gas for the power sector; Armenia: Gas or new NPP to meet long-term forecast demand

Supply Security

Challenges

- Dilapidated critical power transmission lines
- Dilapidated critical substations

Solutions

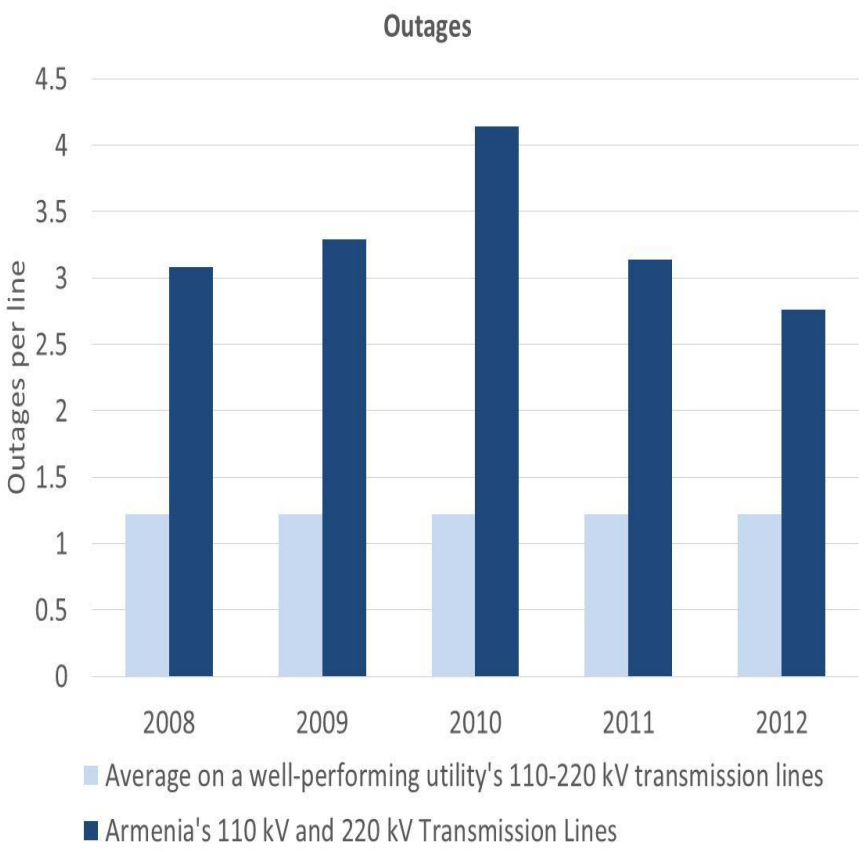
- Prioritize investments
- Rehabilitate existing assets

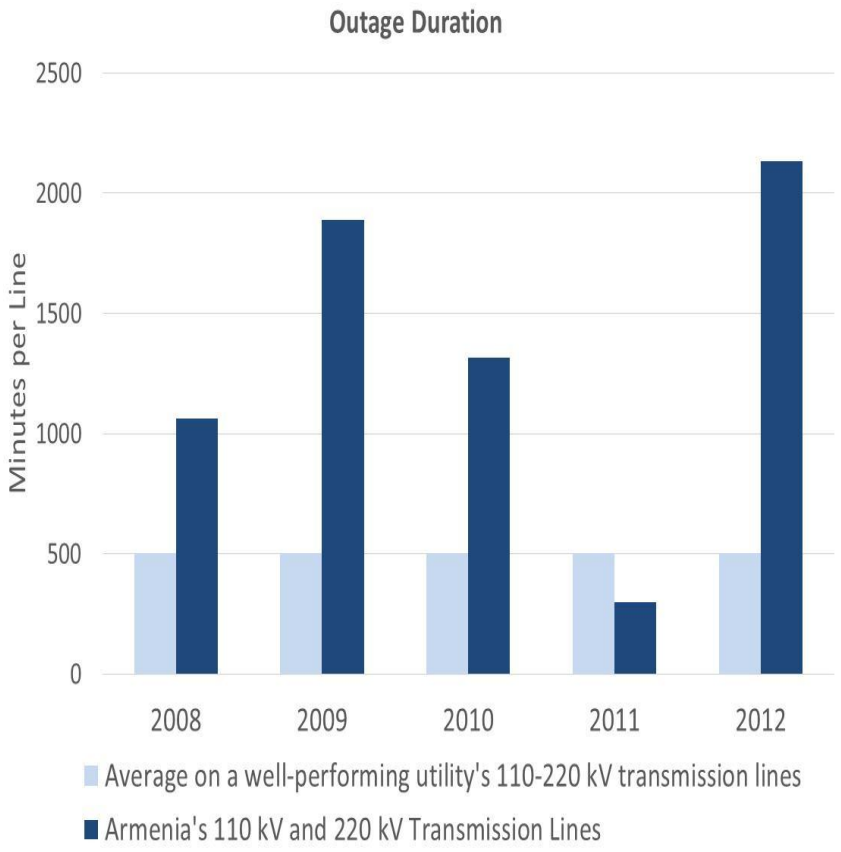
Key Next Steps

- **Adopt "Risk Index" for prioritization of transmission investments**
- **Secure financing for rehabilitation of critical transmission lines and substations**

Challenge #2: Supply Security

Outages per transmission line 2.5 times higher than the average for well-performing utilities*





* An average of a number of US and European utilities

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Challenge #2: Supply Security

- **Poor condition of critical power transmission assets jeopardizes supply security**
- **HVEN does not have a methodology for prioritizing transmission investments**

1. Poor condition of several critical transmission assets due to age (>45 years) and absence of investments in:

- Substations used to evacuate power from large generators (e.g. substation of ANPP)
- Critical power transmission lines evacuating power from large generators (e.g. Echmiadsin 110 kV OTLs from ANPP)

2. Economic costs of bottlenecks include:

- **Suboptimal dispatch:** Additional cost incurred due to the failure of a transmission asset that forces generation resources to be dispatched in a sub-optimal way
- **Emergency repairs:** Additional costs incurred by the need for unplanned emergency repairs and replacements when assets unexpectedly fail.

3. Lack of formal methodology for prioritizing transmission investments leads to: (a) ad-hoc decision-making on investments, and (b) difficulty to secure much needed investments

Solutions: Supply Reliability: Prioritization of Investments

Develop/adopt a methodology for prioritizing transmission investments

- **Long-term**: Full scale risk assessment based on detailed, component-level information on condition of each asset in the system. Major engineering undertaking.
- **Short-term**: Basic risk assessment based on available data. A "Risk Index" can be created based on assessment of:
  - Consquences of Failure (CoF): a higher score means a greater impact on end-users
  - Probability of Failure (PoF): a higher score means higher probability of failure, based on asset-specific information about:
    - The age of the asset relative to its useful life
    - The number of outages experience by that asset over the past five years, and
    - The duration of outages experienced by that asset over the past five year

Solutions: Supply Reliability: Risk Index

Risk Index (RI) can be adapted to available data to prioritize investments

The Risk Index is calculated as the estimated product of the Probability of Failure (POF) and Consequences of Failure (CoF):

1. **PoF** is computed by scoring each asset on the average of three metrics:
   - % of life remaining
   - Number of outages in 2008-2013
   - Duration of outages in 2008-2013
2. **COF** is a quantitative measure of the consequences of an asset's failure for the system

CoF x PoF = Risk Index

Asset Category	Score
Substations at generators	5
Primary lines from generators	4
Secondary lines from generators	3
Other 220 kV lines or substations	2
Other 110 kV lines or substations	1

% of remaining life	Score
<20%	5
21-40%	4
41-60%	3
61-80%	2
>80%	1

# of outages	Score
51+	5
31-50	4
11-30	3
1-10	2
0	1

Duration of outages (minutes)	Score
1,441+	5
61-1,440	4
11-60	3
1-10	2
0	1

Solutions: Supply Reliability:110 kV Lines

- **7 lines have high rehab priority with total investment cost of $16 million**
- **Those lines serve generation units with a failure likely to cause system wide outages**

Echmiadsin and Shahumyan-2 lines are critical for reliability and safety of ANPP

Bjni and Shahumyan-1 also serve ANPP

Line	Priority Rank	Length (km)	Cost	Financing Status
Sevan	2	10	$1.0	Not secured
Echmiadsin	3	24	$3.3	Not secured
Shahumyan-2	5	33	$3.0	Not secured
Karmir-2	6	10	$0.7	Not secured
Bjni	7	25	$3.8	Not secured
Shahumyan-1	7	14	$3.0	Not secured
Karmir-1	12	10	$1.0	Not secured
TOTAL		**126**	**$16**	

Solutions: Supply Reliability: Transmission Substations

Substation at ANPP has the highest rehab ($20 million) priority given that a failure can cause ANPP safety issues and loss of load

No rehabilitation at Metsamor substation since 1977

Yerevan TPP currently relies on only 110 kV part of substation to connect to transmission grid

Substation	Priority Rank	kV	Financing Status
Metsamor	1	110/220	Not secured
Yerevan TPP/CCGT	1	110/220	ETNIP
Haghtanak	4	220	ESRP AF
Lichk	8	220	PTRP
Shahumyan-2	8	220	PTRP
Vanadzor-1	8	220	ETNIP
Eghegnadzor	8	220	PTRP
Shinuhayr	8	220	PTRP

Substation	Priority Rank	kV	Financing Status
Zovuny	10	220	PTRP
Marash	10	220	PTRP
Charentsavan	10	220	ESRP AF
Ararat-2	10	220	PTRP
Ashnak	10	220	PTRP
Agarak-2	13	220	PTRP

- Armenia does not have operational back-up dispatch center for emergency situations

ETNIP - Electricity Transmission Network Improvement Project (WB)
ESRP AF - Additional Financing for Electricity Supply Reliability Project (WB)
PTRP – Power Transmission Rehabilitation Project (ADB)

Affordability

Challenge

Increasing electricity and gas tariffs

Solutions

Provide targeted assistance through PFBP

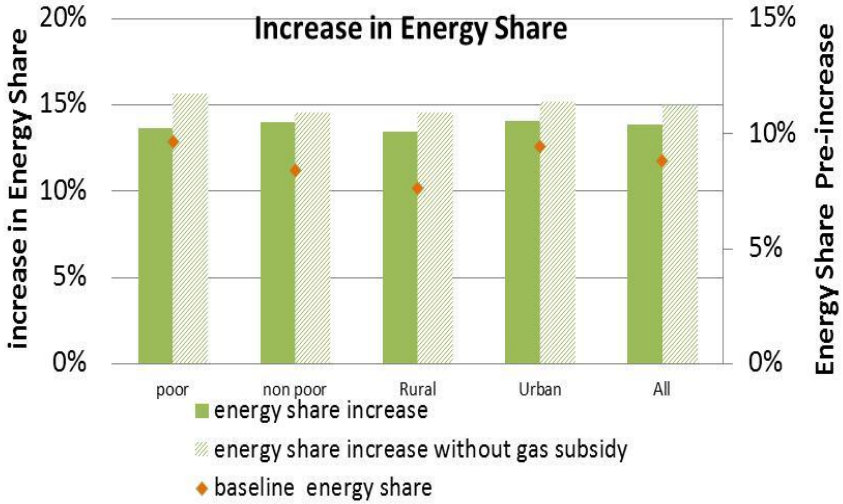
Key Next Steps

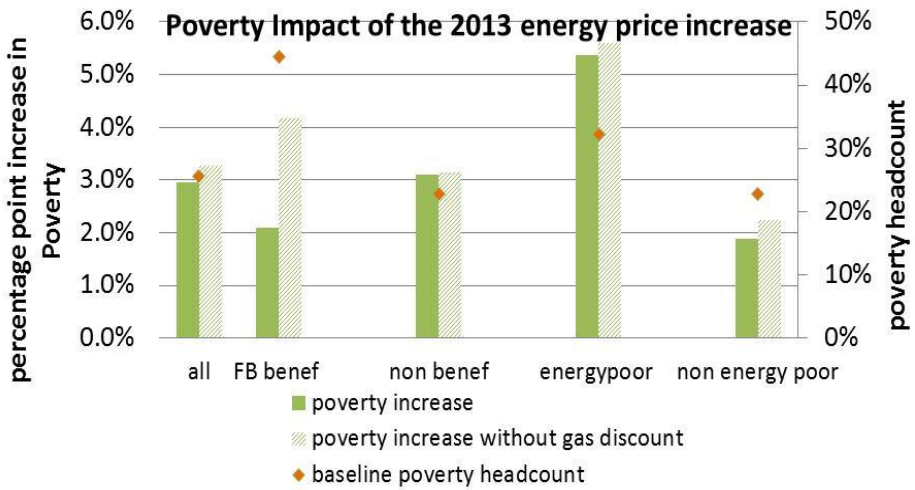
- **Decide on power and gas subsidy option**
- **Improve targeting through better proxy-means testing**
- **Scale up energy efficiency in residential sector**

Challenge #3: Affordability

- **Energy spending as % of total is estimated at 10% – a level considered to be energy poverty**
- **2013 increase of gas and electricity tariffs is estimated to have increased poverty by 3%**

Energy expense share increase was highest for the poor – 13.6%
Without gas subsidy provided by the Government since 2011, the increase of the energy share of expenditure for the poor would have been 15.7%





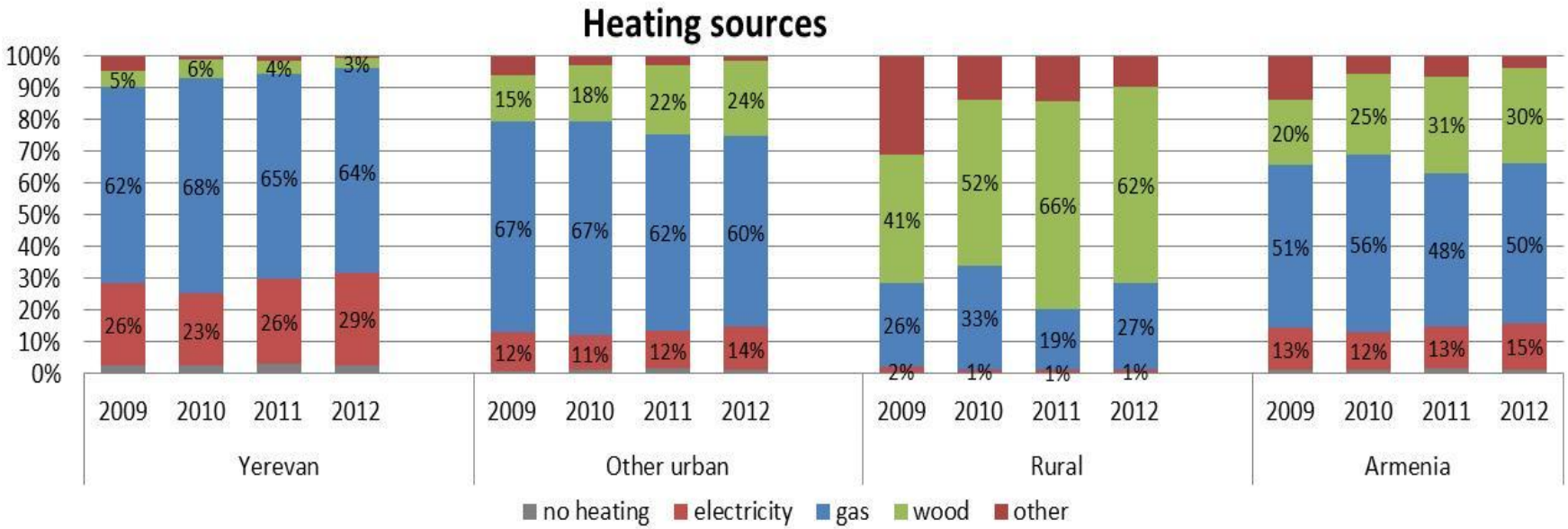
Since April 2011, families registered in PFBP with poverty score above zero paid a reduced tariff of AMD100/m^3 for first 300 m^3 of consumption

*Energy/electricity poverty refer to households spending more than 10% of their budgets on energy or electricity.

Challenge #3: Affordability

Share of gas-based heating is reducing, while wood-based heating is increasing

- Gas based heating may reduce further given significant gas tariff increase in 2013
- Electricity based heating cannot substitute gas given it is 2x more expensive
- Increased use of wood for heating has long-term negative consequences for:
  (a) Public health given higher likelihood of poisonings and accidents with custom-made heaters
  (a) Forests covering only 9% of Armenia's territory



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Challenge #3: Affordability: Results of Qualitative Survey

Poor families struggle to ensure adequate heating

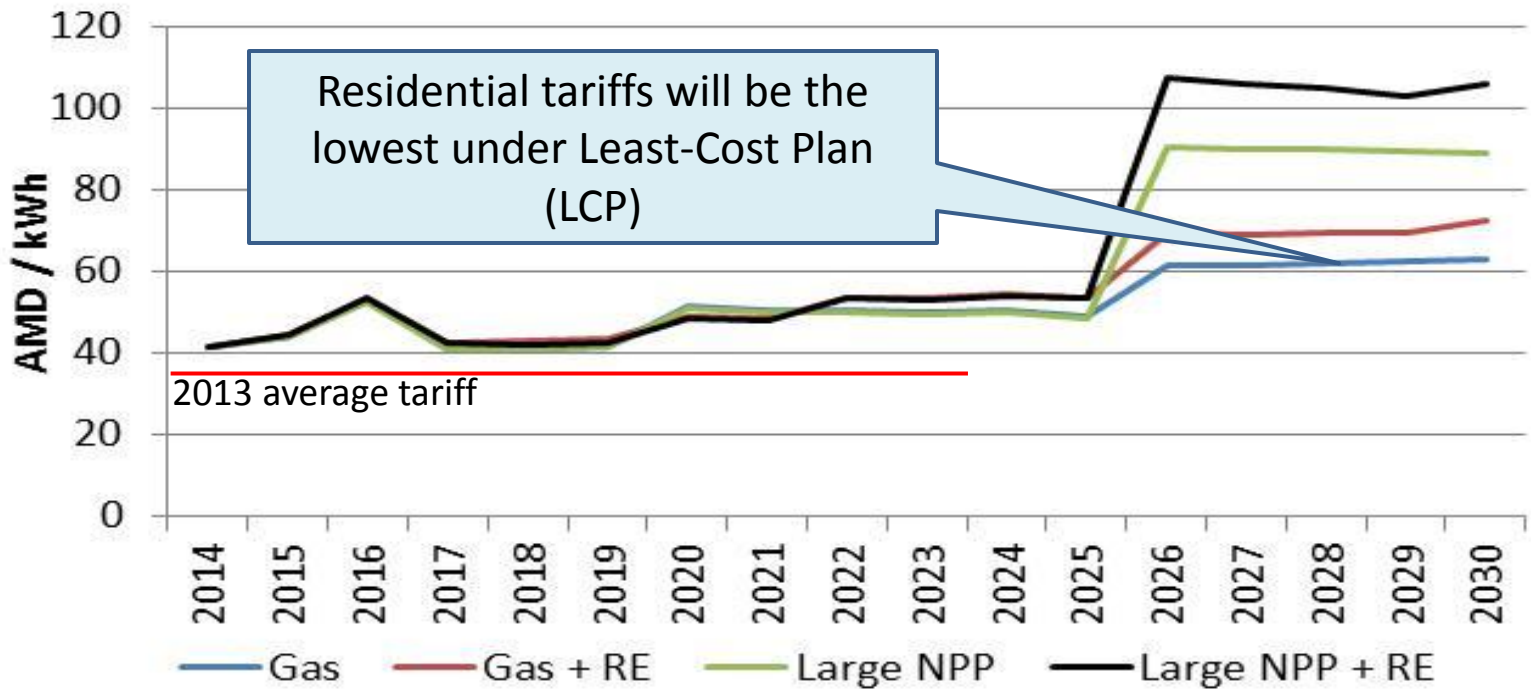
Results of a qualitative heating survey conducted during 2013/2014 heating seasons suggest that:

- FBP recipients reported substituting gas with wood so to avoid consuming >300 m^3 - threshold for FBP eligibility. The costs of energy use for these households may be underestimated if wood costs are not considered.
- FBP recipients reported using the total amount of assistance on energy during the heating season.
- Poor households reported cutting down on expenses for healthcare and children's education to cope with energy price increases. Some also report burning old furniture and clothing when they cannot afford wood.
- Manure is a last resort source of energy that is increasingly used in rural areas.
- Poor households reported that they could no longer reduce their energy use without major impact on their health

Challenge #3: Affordability

Large tariff increases will be needed:

- **In 2016, because highest-cost Hrazdan TPP will need to be run to replace ANPP for a year**
- **In 2020, under all supply plans given the cost of new gas CCGT**
- **In 2026, under all supply plans given the cost of new generation**

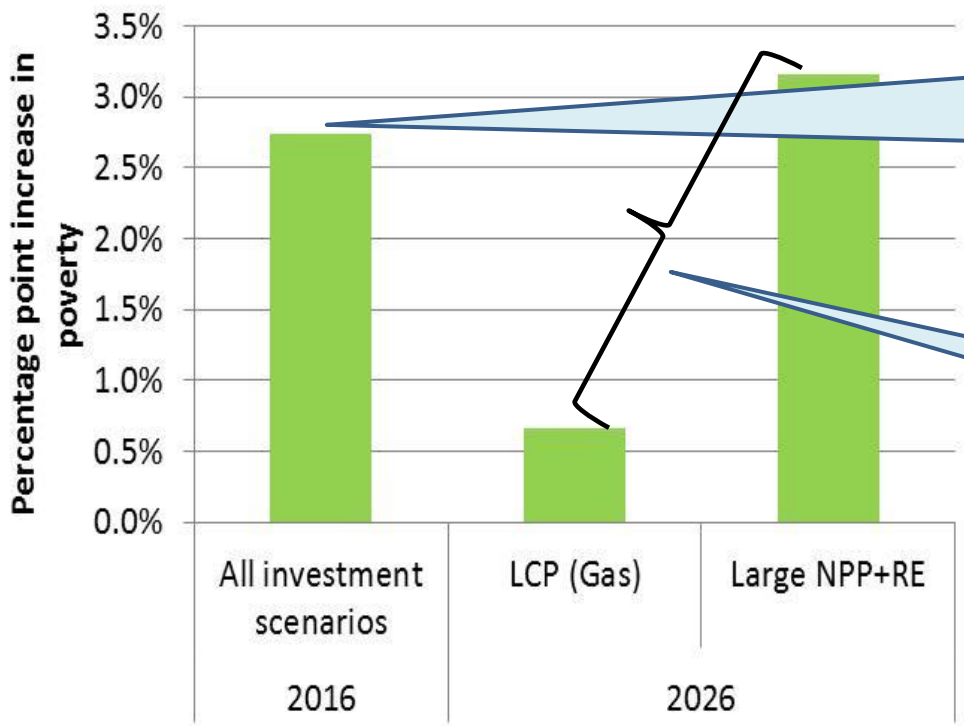


Note: All tariffs are in 2013 prices

Note: Tariffs were computed using marginal cost based methodology; swap with Iran was included in the forecast of tariffs

Challenge #3: Affordability

LCP will have the lowest impact on poverty



In 2016, tariffs will increase poverty by 2.8% under all investment scenarios given that expensive Hrazdan TPP will need to replace ANPP for a year

However, in 2026, LCP (Gas) will increase poverty only by 0.7%, whereas "Large NPP+RE" by 3.2%

Note: Tariffs were calculated assuming commercial financing for all investments given that public financing is not realistic from public debt sustainability perspective
Note: Impacts of all other scenarios fall in between "Gas" (LCP) and "Large NPP + RE" (highest-cost)

Solutions: Affordability: Trade-Offs Involved

Coverage, targeting and fiscal trade-offs are involved when selecting subsidy delivery mechanism

	Advantages	Disadvantages
Lifeline tariff through existing PFBP	• Fairly good targeting (53% of beneficiary households are poor) • Low administrative costs • Public perception of specific measure to protect the poor	• **Limited coverage** - only 16% of poor and 10% of population • No incentives for energy efficiency and conservation • *No rationale* to deliver the benefit through bill in case of electricity,
Additional cash benefit to recipients of PFBP	• No additional administrative costs • More efficient than in-kind subsidy of electricity	• Limited coverage of poor (16%) • Increased horizontal disparity between covered and non-covered poor by PFBP • May be perceived as a benefit increase, not energy-specific (needs appropriate communication)
Cash transfer to all in database with score >0	▪ Broader coverage than PFBP (14% of population in 2012)	• Unknown targeting performance, likely worse than PFBP

Solutions: Affordability: Overview of Options

Affordability for the poor will depend on methodology for quantifying the benefit

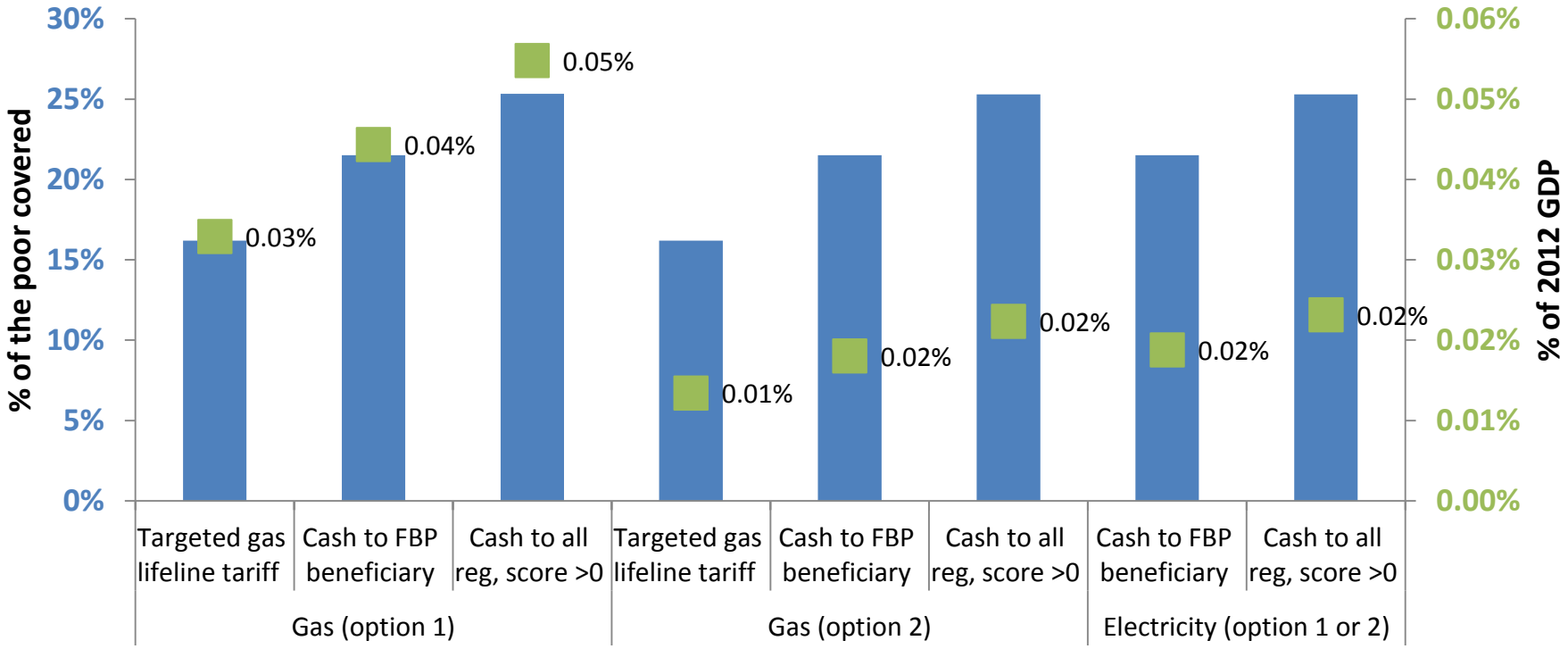
Objective	Description	Annual cost per adult-equivalent	Average annual benefit
Option 1. Mitigation of each tariff increase (2013 used in analyses)	Benefit is calculated to allow households to maintain same level of consumption despite price increase. Does not attempt to mitigate existing energy deprivation	5,880 AMD (2,880 gas & 3,000 elect)	19,400 AMD (9,500 elect + 9,900 gas) (5% of mean annual FBP transfer)
Option 2. Closing gap in consumption between Q1 and Q2	Amount needed to close the gap between the median spending on energy of 2nd lowest and the lowest quintile, assuming Q2 is not as energy deprived	10,000 AMD (5,000 gas & 3,000 elect)	32,600 AMD (9,900 elec. + 22,700 gas) (9% of mean annual PFBP transfer)
Option 3. Meeting minimum energy needs	Benefit is calculated depending on number of household residents, size of house, region, etc.	Requires further research into standardized levels of energy consumption	

Solutions: Affordability: Short-term Options & Fiscal Costs

With existing targeting mechanism only 16-25% of the poor may be covered at an annual cost of 0.05%-0.08% of annual GDP

Option 1 (tariff impact mitigation) & Option 2 (closing gap between Q1 and Q2) would cost the same for electricity, but Option 2 would be more costly for gas.

Coverage and expenditure of compensation with Options 1 and 2



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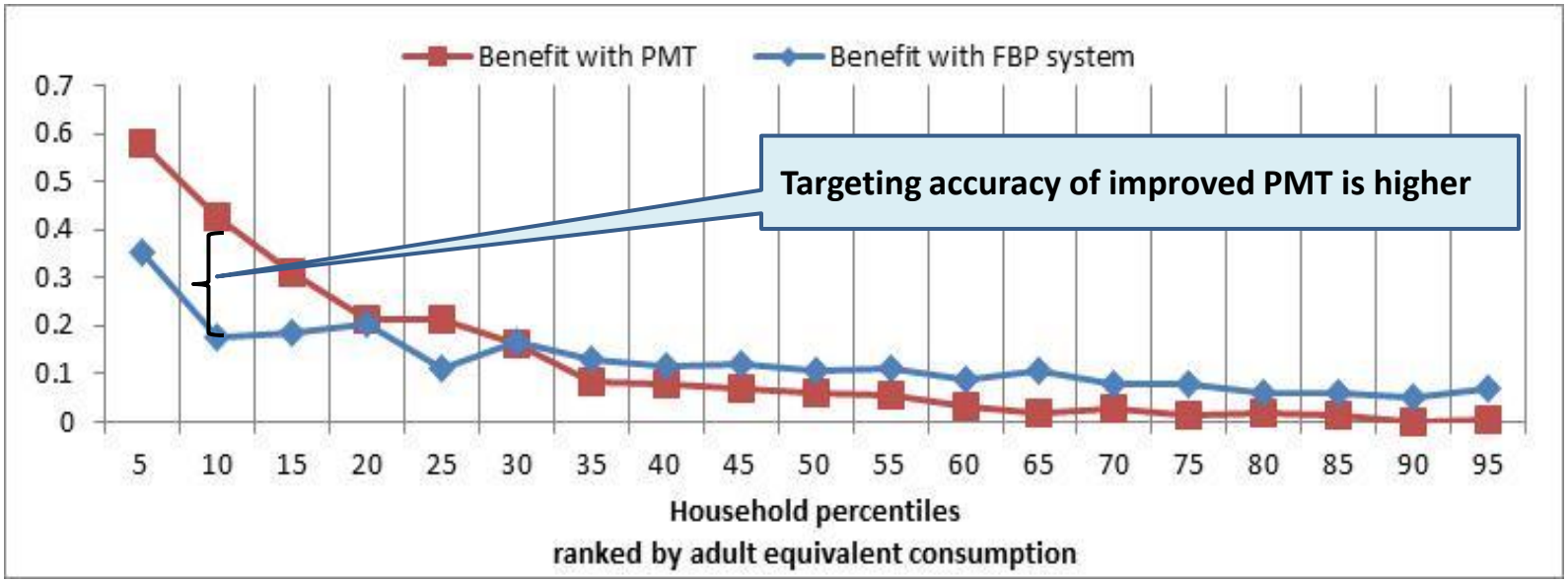
Solutions: Affordability: Medium-term Compensation Options & Fiscal Costs

Broadening coverage to more households will require an updated targeting system

Improving targeting will require:

- A new Proxy Means Testing (PMT) formula that uses information on household composition and characteristics, *traceable* expenditure and incomes, to derive a probability of households being at specific income threshold
- Extensive piloting in welfare centers, and close monitoring during implementation



Covering 40% of poor with new PMT cost 0.09% of GDP, compared to 0.07% of GDP to cover 21% of the poor under existing targeting mechanism of PFBP

Governance

Challenges

- Imprudent financial management of state power companies
- Tariffs frequently lagging cost-recovery
- Power sector assets sold through direct negotiations
- Public communication requires improvement

Solutions

- **Design and implement a financial recovery plan for state-owned power companies**
- **Consistently maintain tariffs at full cost-recovery levels**
- **Sell power sector assets through competitive tenders**
- **Improve communication of sector issues to key stakeholders and general public**

Challenge #4: Deteriorating Governance: Financial Mismanagement

The state-owned power companies are in financial distress: AMD24 billions of debts and payables (27% of their total revenue)

The financial standing of state-owned power companies deteriorated due to:

Low tariffs: The Government tried to mitigate the impact of gas price increases on end-user electricity tariffs by significantly reducing the O&M expenses and by virtually eliminating the profit and depreciation allowed in the tariffs.

"Life support" to non-functional chemical plants: The Government used the funds of the state-owned power companies to finance salaries of the Nairit and Vanadzor chemical plants. The total debt of those chemical plants to the power sector is estimated at AMD22 billion.

Financing of the gas subsidy for the poor: The state power sector companies were mandated to finance the ADM1.1 billion gas life-line subsidy to the poor.

Financing of non-core business assets: The power sector carries on its balance and pays for operation and capital renovation of a large center used for official government receptions.

Challenge #4: Deteriorating Governance: Tariffs

In recent years, tariffs were frequently lagging cost recovery

In 2009-2013, tariffs were lagging cost recovery because of:

- 0 or reduced depreciation and return on assets for state-owned companies (e.g. HVEN, Vorotan, Yerevan TPP)

Tariffs (AMD/kWh), VAT inclusive	1-Apr-09	1-Oct-09	1-Apr-10	1-Apr-11	1-Apr-12	7-Jul-13	1-Aug-14
HVEN	1.1	0.4	0.9	1.0	0.4	1.3	1.6
Vorotan	1.7	1.2	2.2	5.3	5.7	9.5	9.4

- Negligible contributions to ANPP decomissioning fund. Around $7 million is accumulated in ANPP decommissioning fund whereas around $350 million* will be required starting from 2026

- Reducing margin of the distribution company (Electric Networks of Armenia, ENA) due to:
  - Significant unexpected increase of costs due to longer-than-usual periodic maintenance of ANPP and the need to buy significantly more expensive replacement power from Hrazdan TPP; and
  - Unchanged end-user tariffs.

  Reduction of the margin had negative financial implications for ENA and may jeopardize reliability of supply

  :

  - ✓ ENA capital investments reduced from AMD 28 billion in 2009 to AMD 8 billion in 2012
  - ✓ ENA net profit margin reduced from 3.2% in 2010 to negative 9.2% in 2012

* USAID estimate, 2008

Challenge #4: Deteriorating Governance: Sale of Vorotan and Financial Management

- **Direct negotiated sale of Vorotan hydropower cascade**
- **Imprudent financial management decisions at some state-owned companies**

Sale of Vorotan could have been done through competitive process to maximize the benefits:

- **The GoA received $180 million for 404 MW Vorotan Cascade**. This translates into $450,000/MW of installed capacity.
- **One of the GoA objectives was to attract private investments** for much needed rehab. The Government had a Euro 50 million loan from KfW for rehab of Vorotan.
- **One of the GoA objectives was to attract experienced private operator to improve efficiency.** The new private operator (Countour Global) is currently running two hydropower plants in Brazil with installed capacity of 40 MW.* Vorotan has been operated by a competent team without major incidents.
- **The GoA disclosed very limited information to the public**

Imprudent financial management decisions at some state-owned companies:

- **HVEN took commercial loans that were lent to Vorotan Cascade and Yerevan TPP:** There were several instances when HVEN assumed short-term commercial debt that was on-lent to Vorotan Cascade and Yerevan TPP because the latter could not borrow due to week balance sheets.
- **HVEN was used to implement a project that was not part of its core business:** HVEN was used as the implementing entity for the construction of new gas pipeline to Iran and was penalized for US$5 million in 2012 for improper tax accounting of the gas pipeline project with significant impact on its financial standing.
- **Huge non-business related expenses**: AMD 400 million payroll of Nairit financed by Vorotan Cascade

* Countour Global web-site, http://www.contourglobal.com/portfolio#, accessed on August 10, 2014

Challenge #4: Deteriorating Governance: Communication

Fragmented public disclosure and discussion of key power sector issues

- Limited dialogue or openness to discuss sector specific problems with broader stakeholders. Sufficient clarifications and information were not provided to the key stakeholders and general public on: (a) new gas agreements signed with Russia in December 2013; (b) sale of Vorotan Cascade; and (c) benefits for Armenia from electricity-gas swap deal with Iran.
- Inefficient communication of the power tariff review decisions to the public. Recent electricity tariff increases resulted in false public understanding of the reasons for such increase.

<u>Limited public support for power sector projects and reforms</u>:

- Growing, vocal and strong political and social opposition to justified tariff increases
- Public skepticism of ongoing and new investments aimed at improvement of reliability and adequacy of power supply

Solutions: Governance: Financial Recovery Plan and Competitive Sales

- **Design and implement a financial recovery plan for state-owned power companies**
- **Privatize assets through open and transparent competitive tendering**

Design and Implement a financial recovery plan for state-owned power:

- Discontinue financing of chemical plants
- Discontinue the practice of using state-owned power companies to finance the gas subsidy
- Settle the inter-company debts through off-sets and write-offs
- Divest non-core business assets
- Ensure adequate revenue for sector companies to operate and invest in capital repair and adequate O&M to ensure reliable power supply

Consider open and transparent competitive tenders as the preferred approach for sale of energy assets because:

- The legal and regulatory environment in the power sector is conducive for private investments
- The GoA would maximize revenue from asset sales
- The GoA would attract experienced operator(s)s that can improve management and efficiency

Solutions: Governance: Improved Communication

Improvement in communication can generate public support …

Key Pre-Conditions for Improved Communication:

- Development of an action-oriented communication plan with consensus building objectives and goals, core messages and their positioning, key audience, the most appropriate channels in the public domain to ensure smooth implementation
- Gradual public communication on the most critical issues of the sector, including long-term challenges of supply adequacy and related large investment needs, which will require tariff increases

Annexes

Acronyms and Abbreviations

AMD	Armenian Dram
ANPP	Armenian Nuclear Power Plant
BCM	Billion Cubic Meters
CCGT	Combined Cycle Gas Turbine
CNP	China Nuclear Power
COF	Consequence of Failure
CPI	Consumer Price Index
EE	Energy Efficiency
ENA	Electric Networks of Armenia
FBP	Family Benefit Program
GDP	Gross Domestic Product
GWh	Gigawatt-hour
HPP	Hydropower plant
HVEN	High Voltage Electric Networks
kV	Kilovolt
kWh	Kilowatt-hour
LCP	Least Cost Plan
LRAIC	Long-Run Average Incremental Cost
MW	Megawatt
NPP	Nuclear Power Plant
NPV	Net Present Value
OTL	Overhead Transmission Line
POF	Probability of Failure
PMT	Proxy Means Testing
PV	Photovoltaic
RE	Renewable Energy
RM	Reserve Margin
ROR	Run-of-River
TCM	Thousand Cubic Meters
TPP	Thermal Power Plant
WWTP	Waste Water Treatment Plant

Annex 1: Government Objectives

Outlines the GoA's strategic objectives for economic growth, poverty reduction, and national security

Armenian Development Strategy (ADS): 2014-2025

Energy Sector Development Strategy (2005)

Identifies objectives and priorities in the energy sector

National Energy Security Concept (2013)

Emphasizes the importance of investing in infrastructure

<u>Objectives in the Energy Sector:</u>

i. uninterrupted supply of energy
ii. satisfaction of basic needs of consumers: affordable prices, reliable energy supply and energy efficiency
iii. minimize economic effects of importing energy
iv. safe operation of ANPP until it can be replaced with a new NPP
v. environmentally viable energy supply
vi. creation of financially viable energy system
vii. maintenance and further development of export oriented and economically efficient power system.

Annex 1: Government Objectives, Cont.

Energy Sector Development Strategy (2005)

Action Plan of the MENR (2007)

National Program on Energy Saving and RE (2007)

National Energy Security Concept (2013)

Policy direction & specific measures

1. Development of energy security system:

- Identify energy security threats
- Improve institutional & legal foundations
- Gradual liberalization of energy markets

2. Efficient use of own resources:

- Increase use of RE resources
- Promote EE
- Explore potential of bio fuels and other possible fuel alternatives
- Search for new fossil fuel deposits
- Diversify imports

3. Safe operation of ANPP & construction of a new NPP:

- Complete ANPP safety enhancement and maintain safe operation
- ANPP decommissioning Feasibility study, design works and commissioning of new ANPP unit

4. Diversification of energy supply & regional integration:

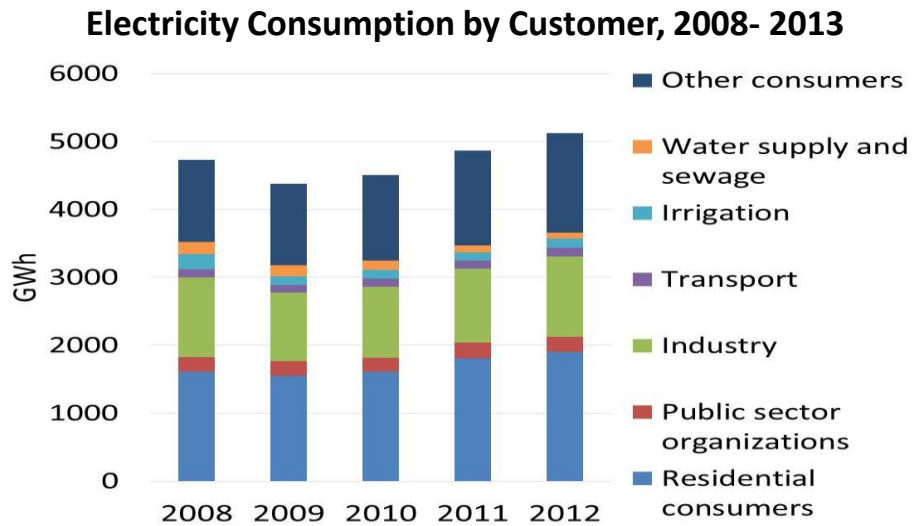
- Gas storage
- Develop oil reserves
- Armenia-Iran and Armenia-Georgia 400/500 kV transmission lines
- Integration into CIS energy market, regional power markets

5. Ensure financial sustainability and economic efficiency of sector

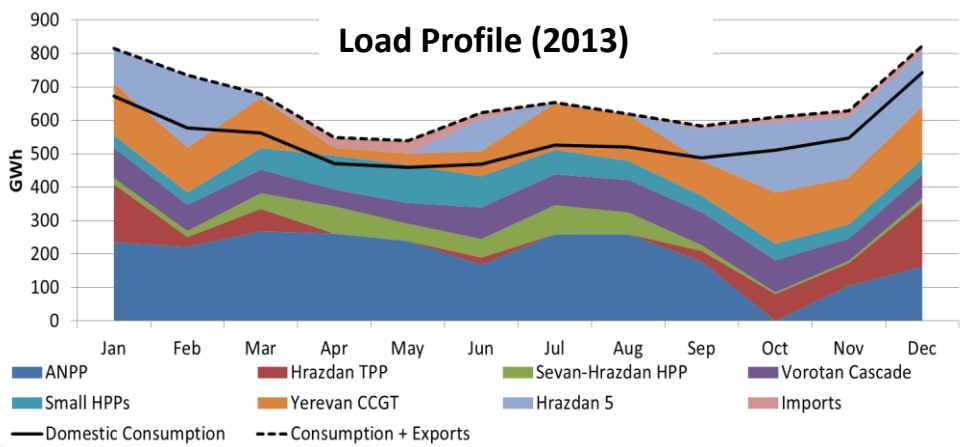
6. Ensure energy security in case of emergency situations or time of war

Annex 2: Overview: Power Sector

2% average annual increase in domestic consumption in 2010-2013



Generation (2013)	
Installed Capacity (MW)	3500
Available Capacity – Summer (MW)	2600 (Higher summer capacity is due to larger availability of hydro)
Available Capacity – Winter (MW)	1900



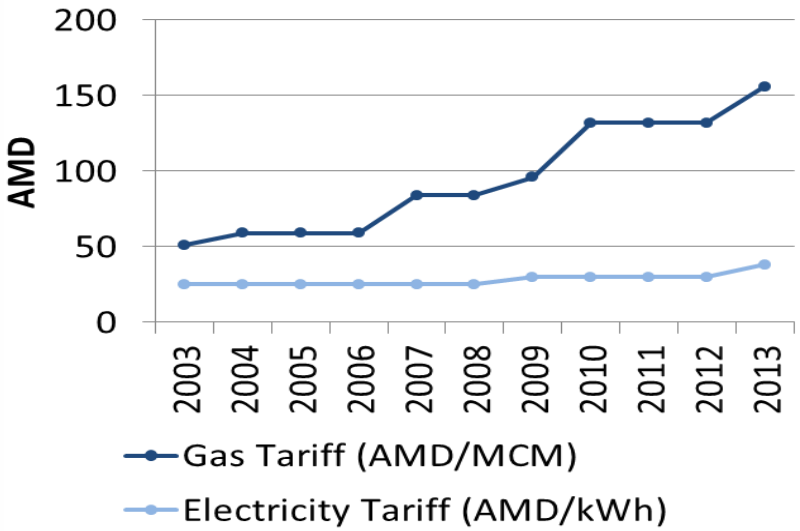
Consumption (2013)	
Total Consumption (GWh)	5267
Summer Peak Demand (MW)	960
Winter Peak Demand (MW)	1520

* Adjusted for unusually cold winter of 2013

Annex 2: Overview: Power and Gas Tariffs

- **Gas and electricity tariffs are at short-term cost-recovery level**
- **In 2010-2013, electricity and gas tariffs for residential customers in increased by 29%**

- Gas tariffs increased due to increase of border price of imported gas from Russia
- Electricity tariffs increased given that 30% of generation is gas-based



- Gas tariffs are differentiated by volume of consumption

- Electricity tariffs are differentiated by voltage levels and time-of-day

Electricity tariffs	Day	Night
	(AMD/kWh)	
Residential	38	28
0.4 kV	38	28
6 (10) kV	35	25
35+ kV	29	25

Gas tariffs	(AMD or USD/cubic meter)
Small consumers (less than 10,000 m3/month	AMD 156
Large consumers (10,000 m3 per month and more)	$277 (AMD 114)

Annex 2: Overview: Gas-for-Electricity Swap with Iran

Since 2011, Armenia has been exporting electricity Iran in exchange for gas

Summary of the Agreement:

- ✓ Gas is imported through the Iran-Armenia gas pipeline with annual capacity of 2.3 billion m^3 (commissioned in 2011).
- ✓ Electricity-for-Gas Swap Agreement targets to increase average annual amount of gas received to 2.3 bcm and electricity supplied – 6.9 billion kWh.
  - Currently only 360 million m^3 received annually in exchange for 1.2 billion kWh
  - Full contractual quantities can be achieved after commissioning of 400 kV transmission line
- ✓ Exchange rates for electricity supplied under the Swap Agreement are differentiated by the time of the day:
  - 12:01 AM – 8 AM: 6 kWh per $1m^3$
  - 8:01 AM – 8 PM: 3 kWh per $1m^3$
  - 8:01 PM – 12:00 AM: 1.5 kWh per $1m^3$
- ✓ Yerevan CCGT is party to the Swap Agreement

Benefits for Armenia:

Helps to reduce the cost of domestic supply:

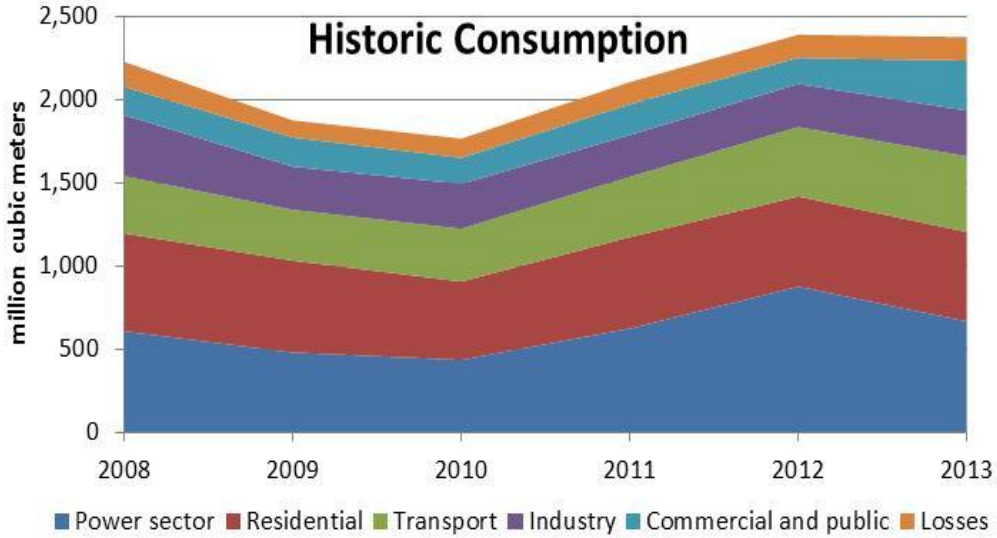
- ✓ New efficient Yerevan CCGT and Hrazdan-5 generate 4.5 kWh with $1m^3$ of gas
- If electricity is supplied during day and peak hours, then Armenia keeps 1.5-4.5 kWh of power as profit
- "Profit" power is sold in domestic market without fuel component in the tariff

Benefits for Iran:

Helps to reduce unmet demand in Northern regions

Annex 2: Overview: Gas Sector

- **In 2010-2013, domestic consumption recovered to pre-crisis levels**
- **Growth in domestic gas consumption driven by power sector**



Vertically integrated monopoly gas company 100% owned by the Russian Gazprom

- 2,000 km transmission pipeline
- 11,000 km distribution pipelines
- Installed gas storage capacity of around 190-195 mln m^3 with current operational capacity of 127-130 mln m^3

	2008	2011	2013
Number of residential customers	490,000	580,000	626,000

Import Pipeline	Capacity (bcm/year)
North-South (gas from Russia)	3.65
Iranian pipeline (gas from Iran)	2.30

* Both pipelines owned by Gazprom

Annex 3: Electricity Demand Forecast Model

- **Econometric model derived to forecast electricity demand in Armenia**
- **Demand forecasts were produced for both residential and non-residential demand**

1) Demand was estimated using a log-log model with the following functional form:

$$Ln(D) = \beta_{\circ} + \beta_1 Ln(Y) + \beta_2 Ln(P)$$

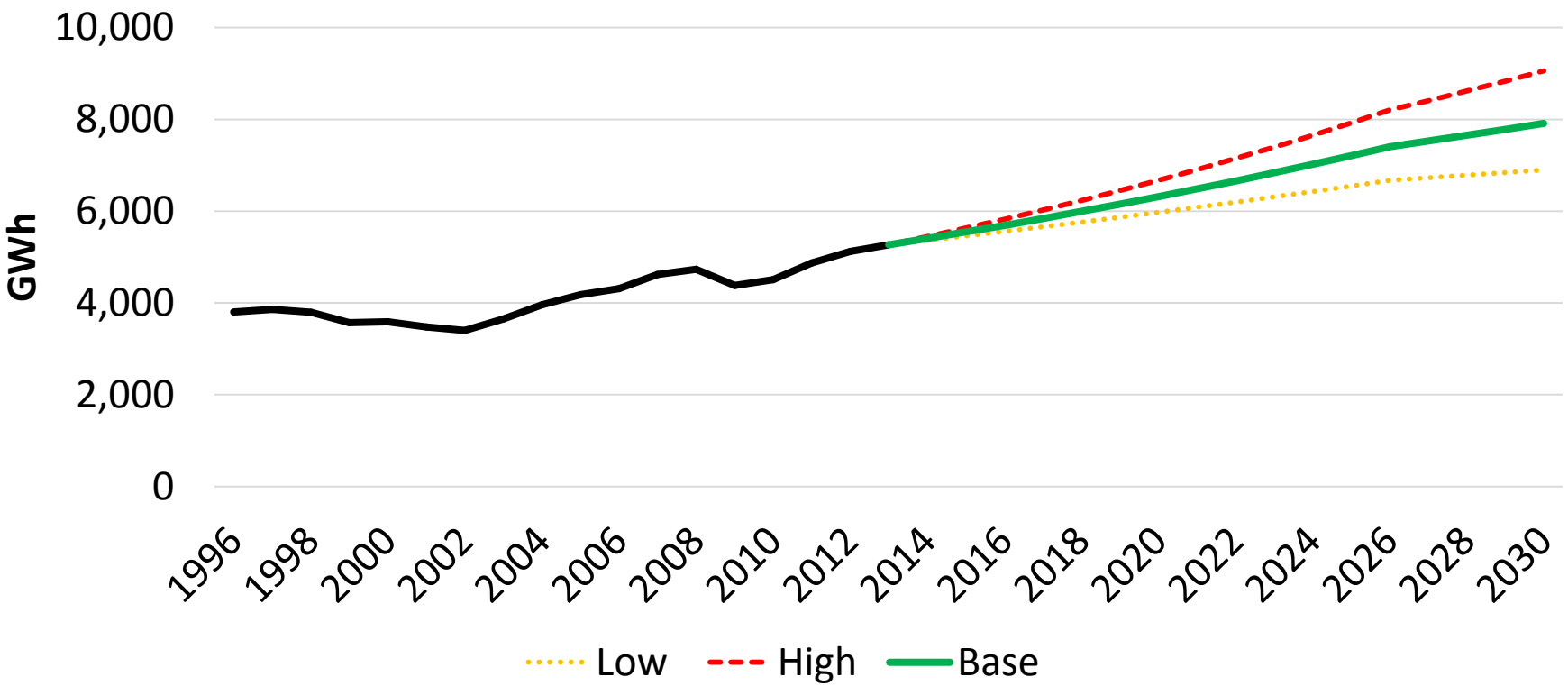
2) The models were fit using data for electricity demand (D), real GDP (Y), and real tariff price (P) for the 1996-2013
3) Assumptions on GDP and tariffs were fed into the models to produce demand estimates
   - GDP was based on ADS 2014-2025
   - For the first iteration of demand forecasts real prices were kept constant
   - For the second iteration, tariffs under the least cost plan were used

Elasticity	Estimate
Residential	
Price	-0.44
Income	0.30
Non-Residential	
Price	-0.17
Income	0.47

Low income elasticity of residential demand is due to 100% access rate and high saturation with household appliances. Low income elasticity of industrial demand is due structure of Armenian economy with forecast growth driven by knowledge intensive and non energy intensive industries (e.g. machinery, IT, software, diamond processing/polishing, tourism)

Annex 3: Electricity Demand Forecast

In 2014-2030, electricity demand is forecast to grow 1.6-3.2% per year

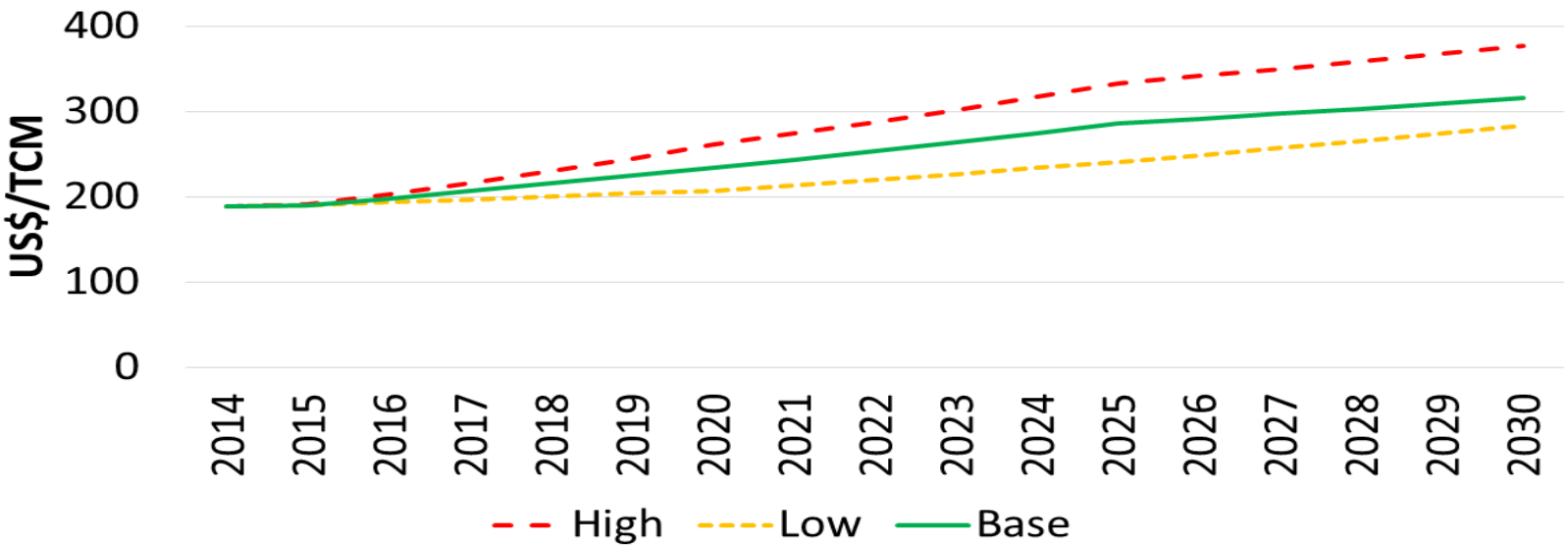


Note: (1) Base GDP growth set using forecasts from the Armenia Development Strategy (2014); low GDP growth is base case minus 2%; high GDP growth is base case plus 2%. (2) Forecast takes into account effects of increased tariffs under least cost plan.

Annex 3: Forecast of Gas Import Price

Russian gas import prices are expected to be more predictable than before

Under the new 2011 agreement, import price of Russian gas is linked to wholesale price in Russia's Orenburg region and US Consumer Price Index and is adjusted annually



Gas Price Forecast assumptions:
Gas price forecasts are based on the Orenburg wholesale gas price scenarios from the "Forecast of Social-Economic Development of Russia until 2030" released by Russia's Ministry of Economic Development and Bank team assumptions on the US Urban Consumer Price Index (CPI-U)

Annex 3: Gas Demand Forecast Model

Constant-elasticity demand function was assumed to derive gas demand forecast

1) Demand was estimated using the following linear functional form:

$$D = a*Y + b*P$$

2) D=average rate of growth of demand between successive forecast periods, a=income elasticity; Y=growth of real GDP between successive forecast periods; b=price elasticity of demand; P=change of real gas prices between successive forecast periods

3) Assumptions on GDP and tariffs were fed into the models to produce demand estimates

- GDP was based on ADS 2014-2025
- Real tariff forecast was derived using forecast domestic price of Russia in Orenburg region and forecast US CPI-U (IMF)

Category of Consumer	Income Elasticity	Price Elasticity
Residential	0.70	-0.25
Industrial and commercial	0.80	-0.10
Transport	0.50	-0.25

Annex 4: LCP Analyses: Methodology

Least-cost planning analyses followed the below methodology

1. A dispatch simulation was run for each supply plan under all demand scenarios to determine the annual kWh output of each plant.
2. Generation and emission costs for each supply plant were calculated:

- Capital costs for each supply plan were calculated given the international prices
- Variable O&M, fuel, and emission costs were calculated using the kWh output multiplied by plant specific characteristics (e.g. heat rate, non-fuel variable cost of generation).
- Fixed O&M was assumed to equal the international benchmarks for each generation technology included in the supply plant
- Emission costs

3. Economic NPV was calculated as the sum of the total cost of generation and emission costs for each supply plan over the planning period, discounted at 10%

Note: Long-run average incremental costs for each supply plan were computed as the ratio of the present value of incremental total costs and present value of all energy generated during the evaluation period

Annex 4: Key Assumptions for LCP Analyses

General Assumptions

- ANPP out for one year in 2016 for life-extension related work
- Hrazdan TPP run until new CCGT is on-line
- Vorotan Cascade and Sevan-Hrazdan Cascades will implement required rehab
- Actual 2013 hourly generation profile of existing HPPs was used for their forecast dispatch
- Iran demand under electricity-for-gas swap deal was modelled assuming actual 2013 hourly exports profile
- Renewable energy technologies were assigned "capacity credit" based on their average capacity during top 10% of load hours in a year (solar PV is assumed 0% availability during peaks)
- No electricity trade with Georgia
- No seasonal electricity swap with Iran
- Gas-for-electricity swap with modelled assuming current levels: 1.2 billion kWh of electricity in exchange for 360 million cubic meters of gas
- CO2 emission costs factored in economic analyses
- Discount rate of 10%

Annex 4: Key Assumptions for LCP Analyses

Capital Cost Assumptions

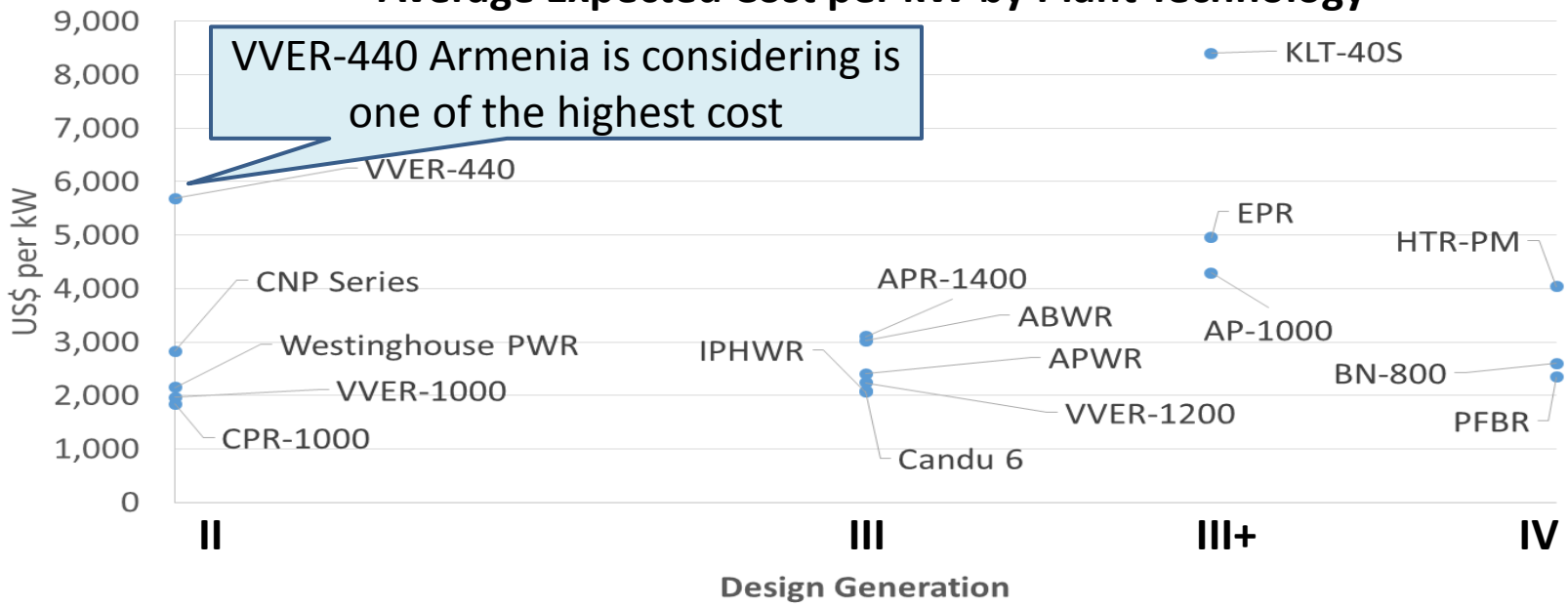
	$/kW	Data Source
Capital cost of new CCGT	1100	Recent CCGT projects in the region
Capital cost of Medium NPP	4250	Ongoing CNP projects
Capital cost of Large NPP	5500	Pre-feasibility study for Armenia VVER-440 reactor, 2010
Loriberd HPP (storage)	2150	Feasibility Study Update, 2009
Shnogh HPP (ROR)	1850	Government and Bank team estimate
Flash cycle geothermal	3700	GeoFund 2: Armenia Geothermal Project
Utility-scale PV	2400	SREP Investment Plan Project
Wind	2200	SREP Investment Plan Project

Annex 4: Nuclear

GoA should consider other commercially available nuclear technologies

- The average expected cost of reactors under construction varies widely from country to country, from a low of US$1,951 per kW (India) to a high of US$6,938 per kW (Finland)
- Average expected costs also vary from $1,841 to $8,400 depending on the NPP technology

Average Expected Cost per kW by Plant Technology

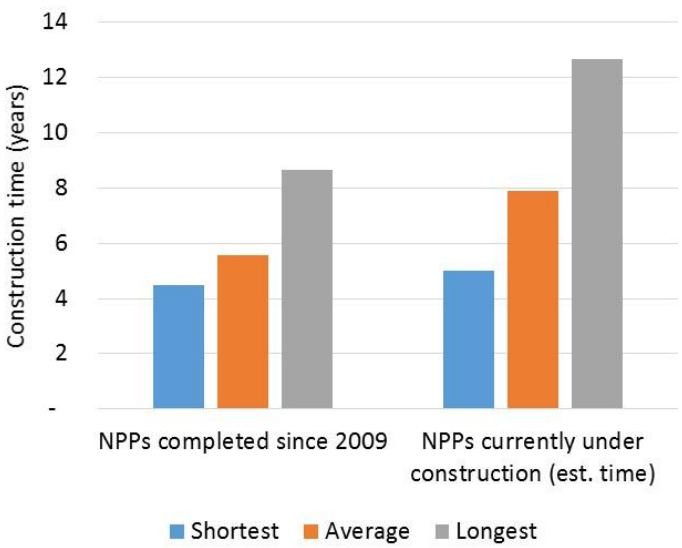


Annex 4: Nuclear, cont.

Average construction time of NPP projects increased

- Construction times have steadily increased since the first nuclear plants were built in the 1960s, and in recent years, they have seen wider variation than ever before.[1]
- Reasons for increased delays in NPP projects include:
  - Regulation and licensing. Licensing delays have increased following the Fukushima disaster.
  - Longer public consultations given increased safety concerns.
  - Scarcity of equipment. Slow global demand has decreased the availability of specialized construction equipment

Recent Experience with Construction Times* of NPPs Globally



Source: Bank Team Research

*Construction times for nuclear units do not include the Owner's development time or licensing activities.

Annex 4: Profile of Loriberd and Shnogh HPPs

Loriberd	Shnogh
Loriberd HPP and Tashir SHPP	
Two construction options: **ROR design** Capacity: 54 MW Production: 208 mln. kWh Cost: $114 million **Peaking Design** Capacity: 66 MW Production: 206 mln. kWh Cost: $128 million **Implementation** - 2 years for technical studies and tender - 5 years for implementation	One construction option: **ROR design** Capacity: 75 MW Production: 300 mln. kWh Cost: $137 million **Implementation** - 2 years for technical studies and tender - 5 years for implementation

Annex 5: Renewable Energy Targets

	Capacity installed (MW)			Generation (GWh)		
	2020	2025	2030	2020	2025	2030
Small Hydro	377	397	397	1,049	1,106	1,106
Wind	50	100	150	117	232	349
Geothermal	50	100	150	373	745	1,116
PV	40	80	80	88	176	176
Total	492	677	777	1,627	2,259	2,747

Note: All RE targets are included in the renewable energy scenarios.