Distribution tariff setting methodologies in Italy

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ECRB - Training on Gas and Electricity Distribution Tariffs
Wien, 17th October 2019

1. Introduction

2. Allowed cost calculation

3. Rate of return calculation method

4. Cost allocation approach

5. Tariffs structure

6. The new challenges

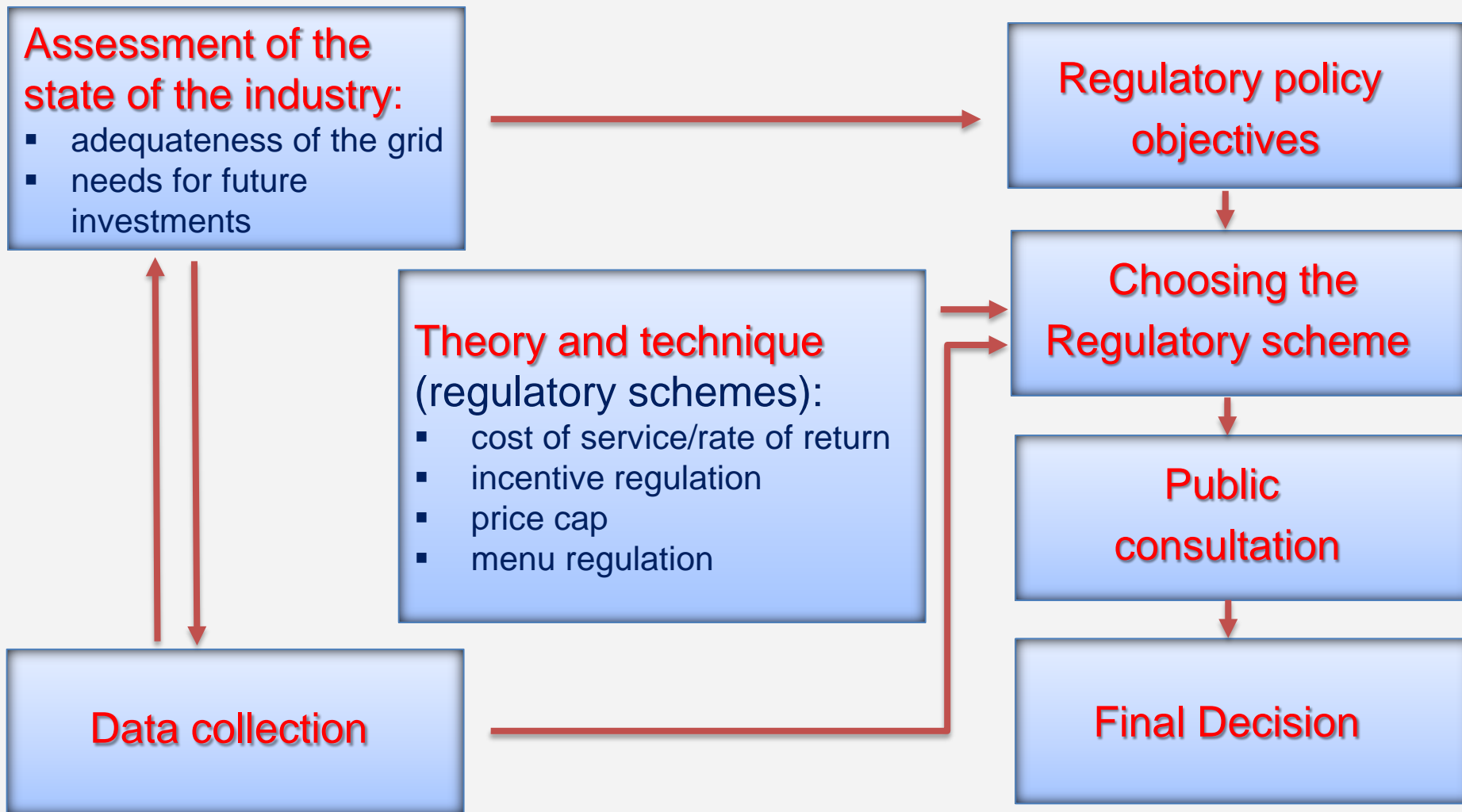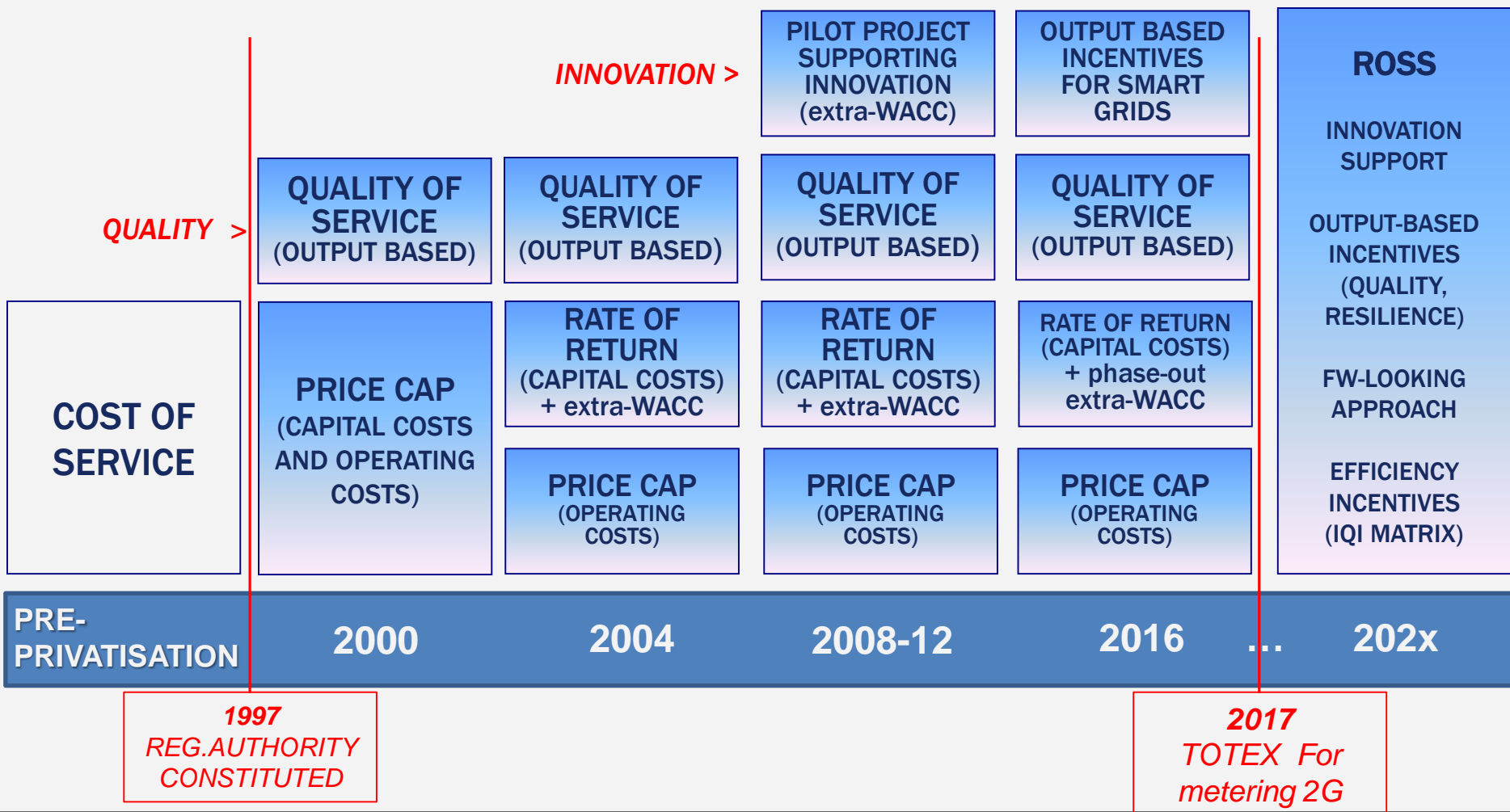## TOPICS

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REGULATORY PROCESS

Assessment of the state of the industry:
- adequateness of the grid
- needs for future investments

Theory and technique (regulatory schemes):
- cost of service/rate of return
- incentive regulation
- price cap
- menu regulation

Data collection

Regulatory policy objectives

Choosing the Regulatory scheme

Public consultation

Final Decision

EVOLUTION OF TARIFF REGULATION IN ITALY

	2000	2004	2008-12	2016	...	202x
			PILOT PROJECT SUPPORTING INNOVATION (extra-WACC)	**OUTPUT BASED INCENTIVES FOR SMART GRIDS**		**ROSS**
INNOVATION >						**INNOVATION SUPPORT**
QUALITY >	**QUALITY OF SERVICE** (OUTPUT BASED)	**QUALITY OF SERVICE** (OUTPUT BASED)	**QUALITY OF SERVICE** (OUTPUT BASED)	**QUALITY OF SERVICE** (OUTPUT BASED)		**OUTPUT-BASED INCENTIVES** (QUALITY, RESILIENCE)
COST OF SERVICE	**PRICE CAP** (CAPITAL COSTS AND OPERATING COSTS)	**RATE OF RETURN** (CAPITAL COSTS) + extra-WACC	**RATE OF RETURN** (CAPITAL COSTS) + extra-WACC	**RATE OF RETURN** (CAPITAL COSTS) + phase-out extra-WACC		**FW-LOOKING APPROACH**
		PRICE CAP (OPERATING COSTS)	**PRICE CAP** (OPERATING COSTS)	**PRICE CAP** (OPERATING COSTS)		**EFFICIENCY INCENTIVES** (IQI MATRIX)

PRE-PRIVATISATION

1997 REG.AUTHORITY CONSTITUTED

2017 TOTEX For metering 2G

GAS AND ELECTRICITY DISTRIBUTION INDUSTRY

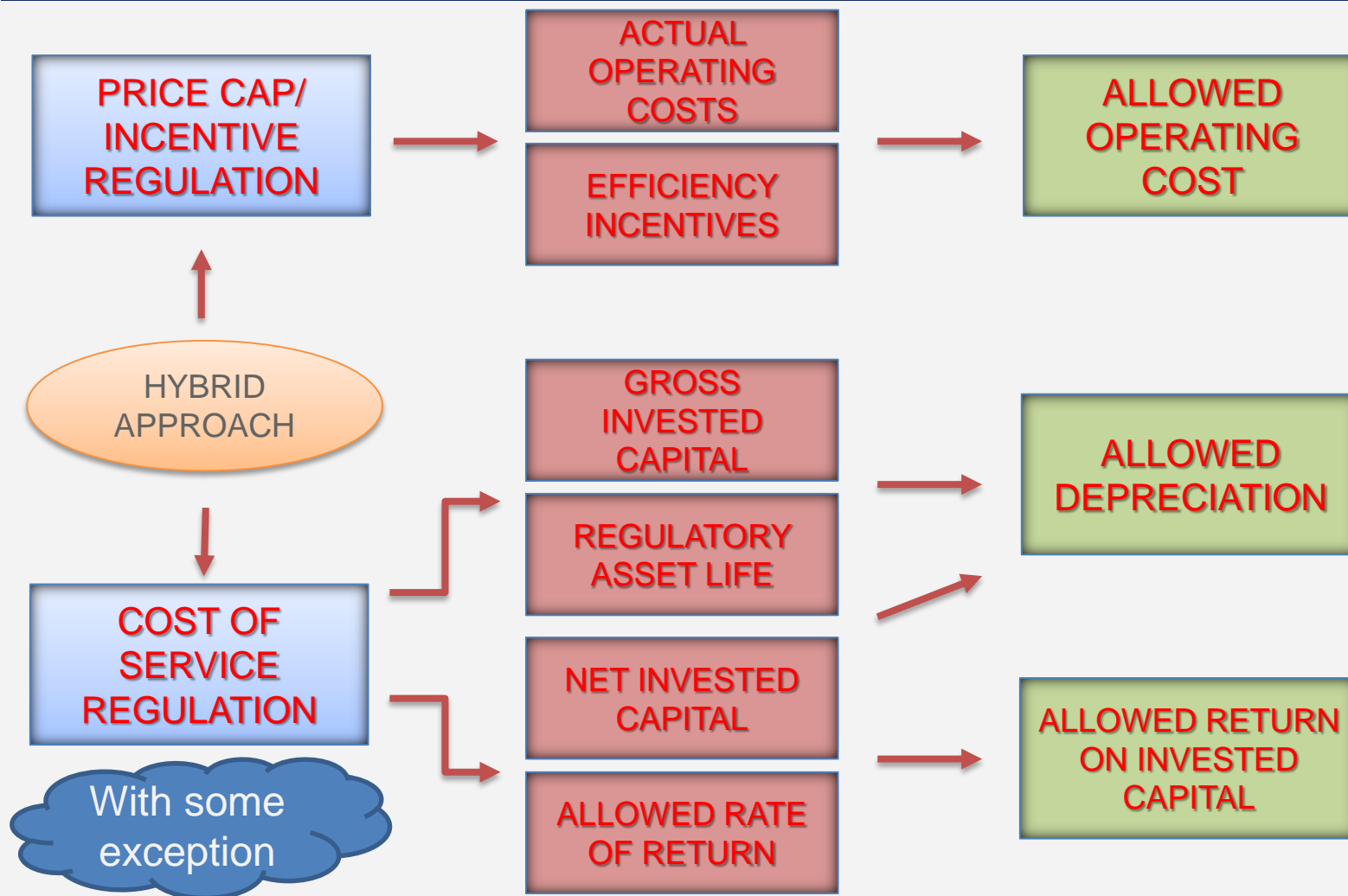|	Electricity distribution and metering	Gas distribution and metering
- number of companies	**>100**	**>200**
- smallest company		
relevant variable	**number of clients served**	**number of clients served**
size	**<5.000**	**<5000**
- largest company		
relevant variable	**number of clients served**	**number of clients served**
size	**>31.000.000**	**>5.000.000**
Volume distributed	**>300 TWh**	**> 30 billion cm**
Big five companies		
1	ENEL DISTRIBUZIONE S.P.A.	Italgas Spa
2	ARETI	2i Rete Gas
3	UNARETI Spa	A2A Spa
4	IRETI SPA	Hera Spa
5	SET DISTRIBUZIONE SPA	Iren Spa
Aggregated RAB (billion Euro)	**23**	**17**

THE CURRENT DISTRIBUTION TARIFF SYSTEM IN ITALY
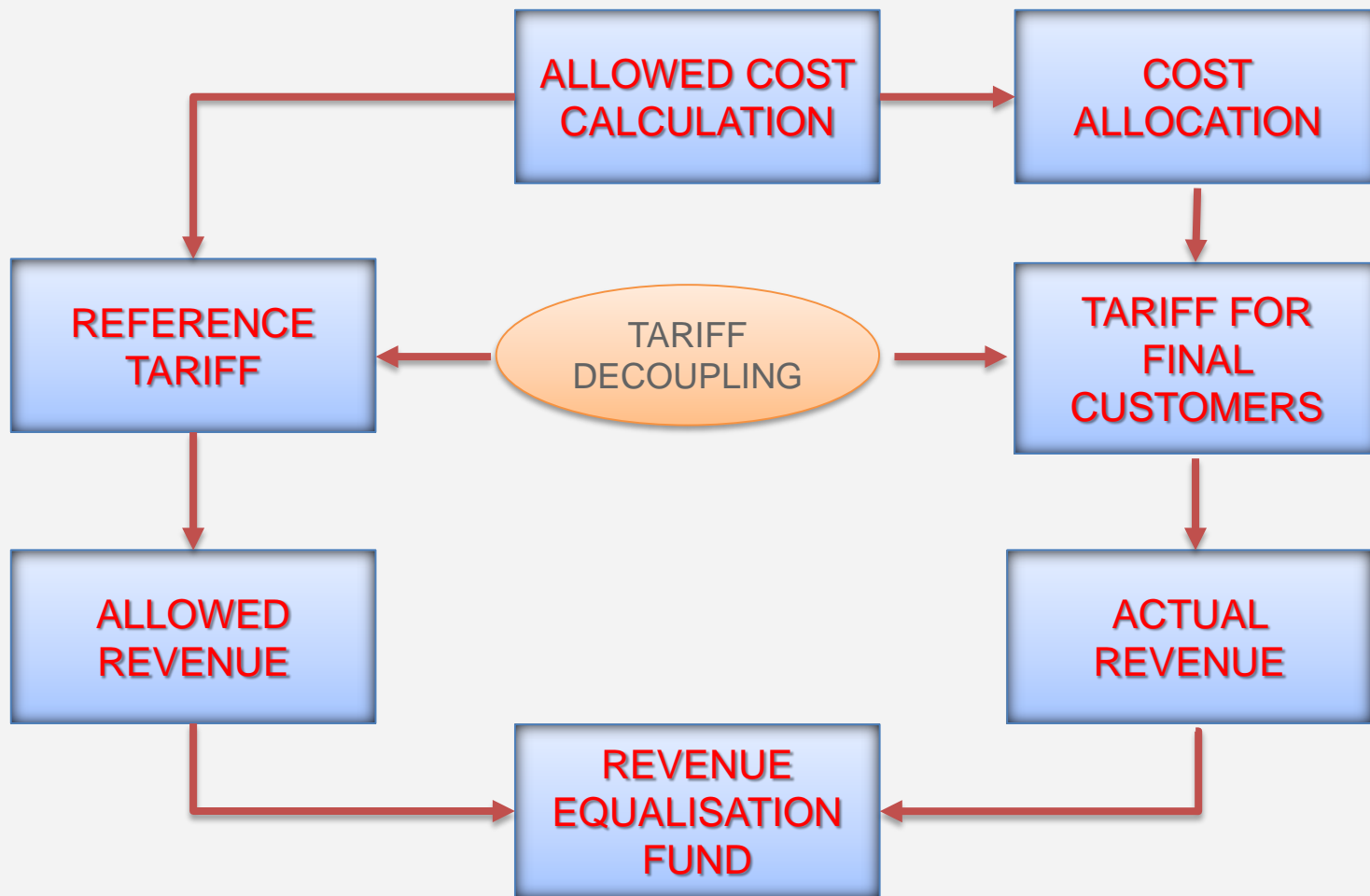
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PRICE CAP/ INCENTIVE REGULATION

ACTUAL OPERATING COSTS

EFFICIENCY INCENTIVES

ALLOWED OPERATING COST

HYBRID APPROACH

COST OF SERVICE REGULATION

With some exception

GROSS INVESTED CAPITAL

REGULATORY ASSET LIFE

NET INVESTED CAPITAL

ALLOWED RATE OF RETURN

ALLOWED DEPRECIATION

ALLOWED RETURN ON INVESTED CAPITAL

ACTUAL OPERATING COSTS

- Allowed operating costs are basically aligned to **actual cost** at the beginning of each regulatory period

- Regulatory period of 6 years (previously 4 years)

- Actual costs are calculated on the basis of costs reported in the **separated annual accounts** according to the unbundling rules defined by the regulator

- Actual costs considered to set the allowed operating costs are net of non-recurring costs, financial costs, advertising and marketing costs, sanctions, tax funds, litigation costs (if unsuccessful), not compulsory insurance costs

EFFICIENCY INCENTIVE MECHANISMS

In relation to the determination of allowed operating costs two incentive mechanisms are applied:

- *price-cap*: annual tariff reviews are based on the *price-cap (RPI-X)* and include **adjustments** reflecting cost variations arising from unforeseeable and exceptional events, changes in regulation and changes in universal service obligations, where applicable *(RPI-X+Y)*

- in the first regulatory periods *x-factor* was based on productivity targets set by the regulators. Since the third regulatory period x-factor are basically used as a tool to redistribute to network users the efficiency gains of the previous regulatory periods, which were temporarily retained by network operators under the so-called 'profit-sharing mechanism

- on the basis of this *profit-sharing mechanism*, at the end of the regulatory period, in order to set tariffs for the following period, efficiency gains are shared between network operators and network users
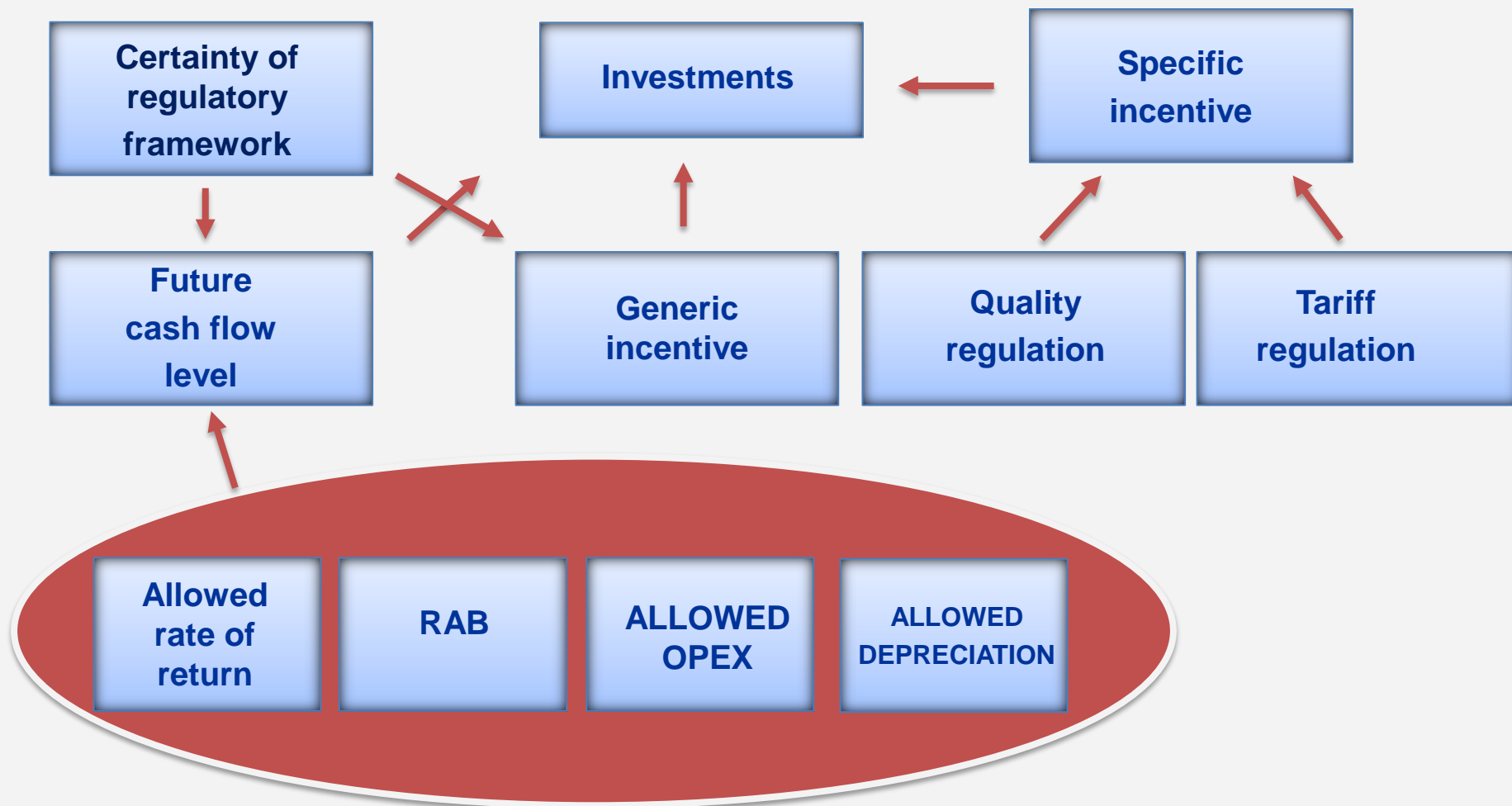
SETTING THE ALLOWED OPERATING COST

Regulatory period I

Effect of price-cap
Incentive to reduce costs= efficiency gains

Regulatory period II

Effect of profit
Sharing mechanism

Legend: ■ Actual opex ■ Efficiency gains period I ■ Efficiency gains period II
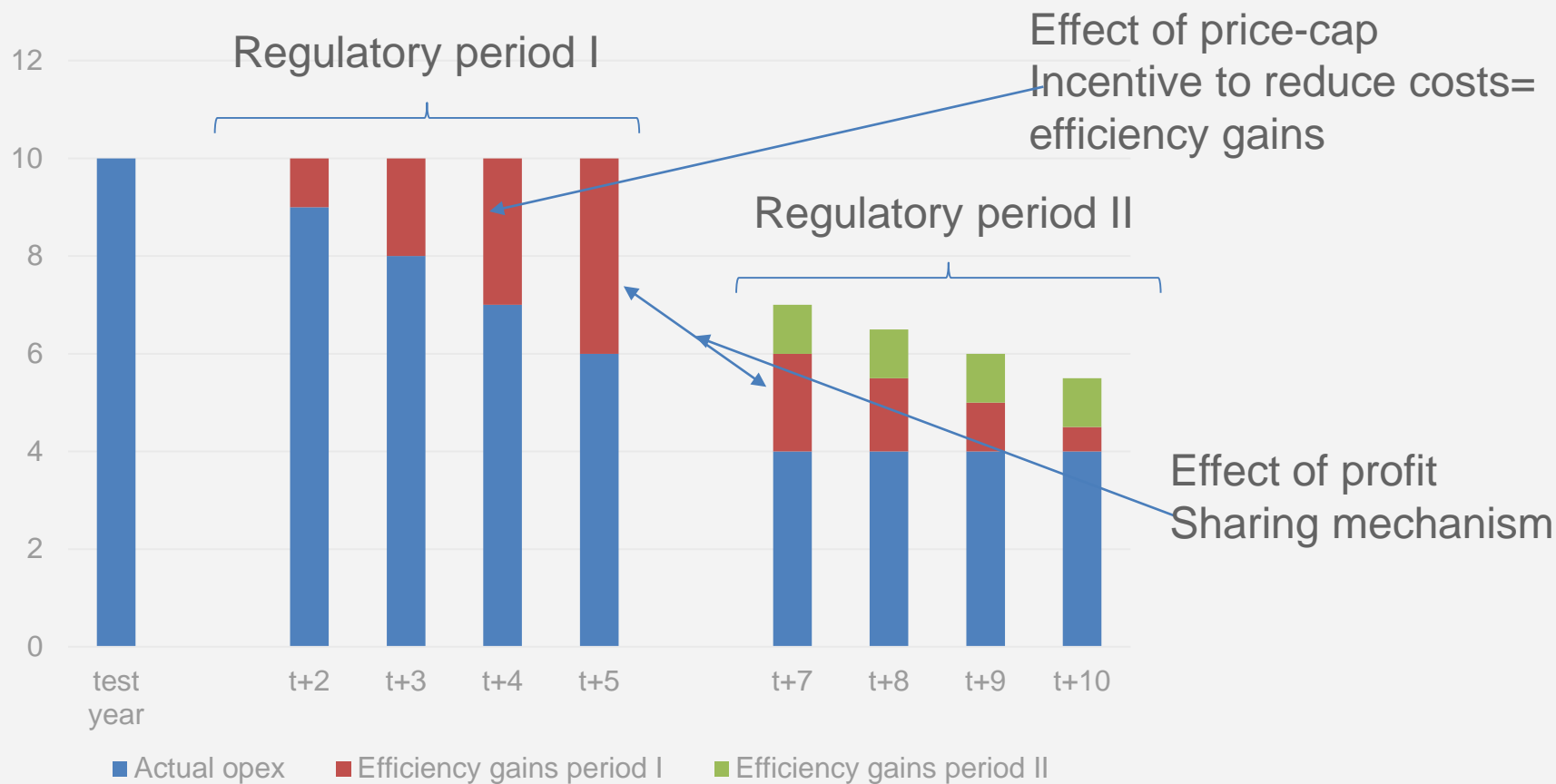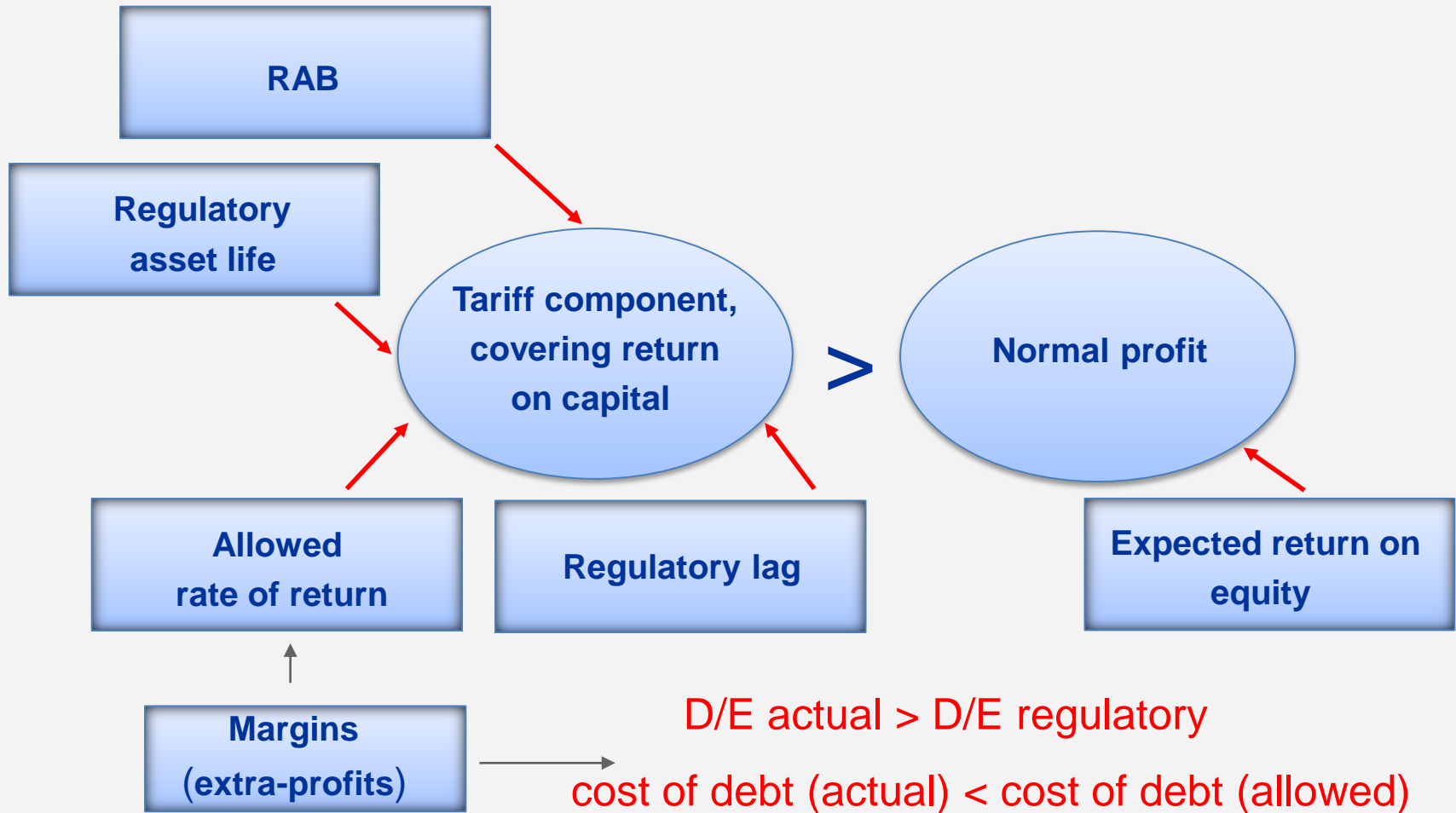
Allowed operating costs

INVESTMENTS: A KEY PROBLEM FOR REGULATORS

- A relevant portion of the costs related to network is cost of capital (about 2/3 of total costs)

- In competitive markets usually the subject who pays for wrong investments is not the customer, but the company. In regulated markets regulators face two opposite risks: on one side the risk of **overinvestment**. On the other side in regulatory context, the long-lived nature of investment in regulated networks means that the risk of creating an **underinvestment** problem is likely to be an important consideration.

- **Lumpiness**: how much to invest? Taking into account only the actual needs of the customer already connected to the network or anticipating investments in order to achieve economies of scale?

VARIABLES INFLUENCING INVESTMENTS

Certainty of regulatory framework

Investments

Specific incentive

Future cash flow level

Generic incentive

Quality regulation

Tariff regulation

Allowed rate of return

RAB

ALLOWED OPEX

ALLOWED DEPRECIATION

GENERIC TARIFF INCENTIVE TO INVEST

RAB

Regulatory asset life

Tariff component, covering return on capital

>

Normal profit

Allowed rate of return

Regulatory lag

Expected return on equity

Margins (extra-profits)

D/E actual > D/E regulatory

cost of debt (actual) < cost of debt (allowed)

GROSS INVESTED CAPITAL

- **Gross invested capital** is expressed at historical revaluated costs

- **Historical costs** are derived from the accounting records of network operators

- **Revaluation** is obtained using the **gross investment deflator index**

- Fixed assets are included in the regulatory asset base (RAB), with a **one-year lag** if investment costs are efficiently incurred and are consistent with system security, follow cost-effective criteria

REGULATORY ASSET BASE

Net invested capital

- **net invested capital constitutes the** regulatory **asset base (RAB) and** is derived from gross invested capital subtracting depreciation fund

- **assets under construction** are also included in the RAB

- RAB is adjusted for:
    - the net real-term (revaluated) value of public grants for infrastructure developments and connection charges
    - the pensionable retirement fund (TFR), calculated parametrically (-1% of net invested capital)
    - the net working capital, calculated parametrically

Yearly update

RAB is updated on a yearly basis taking into account:

- New investments and divestitures
- Changes in depreciation fund
- Changes in public grants and connection charges
- Revaluation - gross investment deflator index

GAS DISTRIBUTION – FIXED ASSET CATEGORIES

- Invested capital can be distinguished by function between:
  - **centralized invested capital**
  - **centralized invested capital relative to metering** (remote metering and concentrators)
  - **local invested capital relative to distribution**
  - **local invested capital relative to metering**

- **Local fixed assets** are:
  - land and buildings
  - citygates
  - mains
  - customers connections
  - conventional meters
  - electronic meters and volumes converter with a data transmission system

- **Centralized assets** relative to distribution are tangible assets not classified as local assets and intangible assets

GAS DISTRIBUTION – EVALUATION CRITERIA

CENTRAL ASSETS - RAB	**STANDARD INVESTED CAPITAL PER FINAL CUSTOMER SERVED**
LOCAL ASSETS DISTRIBUTION AND METERING - RAB	**NET REVALUATED HISTORICAL COST**
LOCAL ASSETS SMART METERS - RAB	**MIX OF NET REVALUATED HISTORICAL COST AND STANDARD COST**
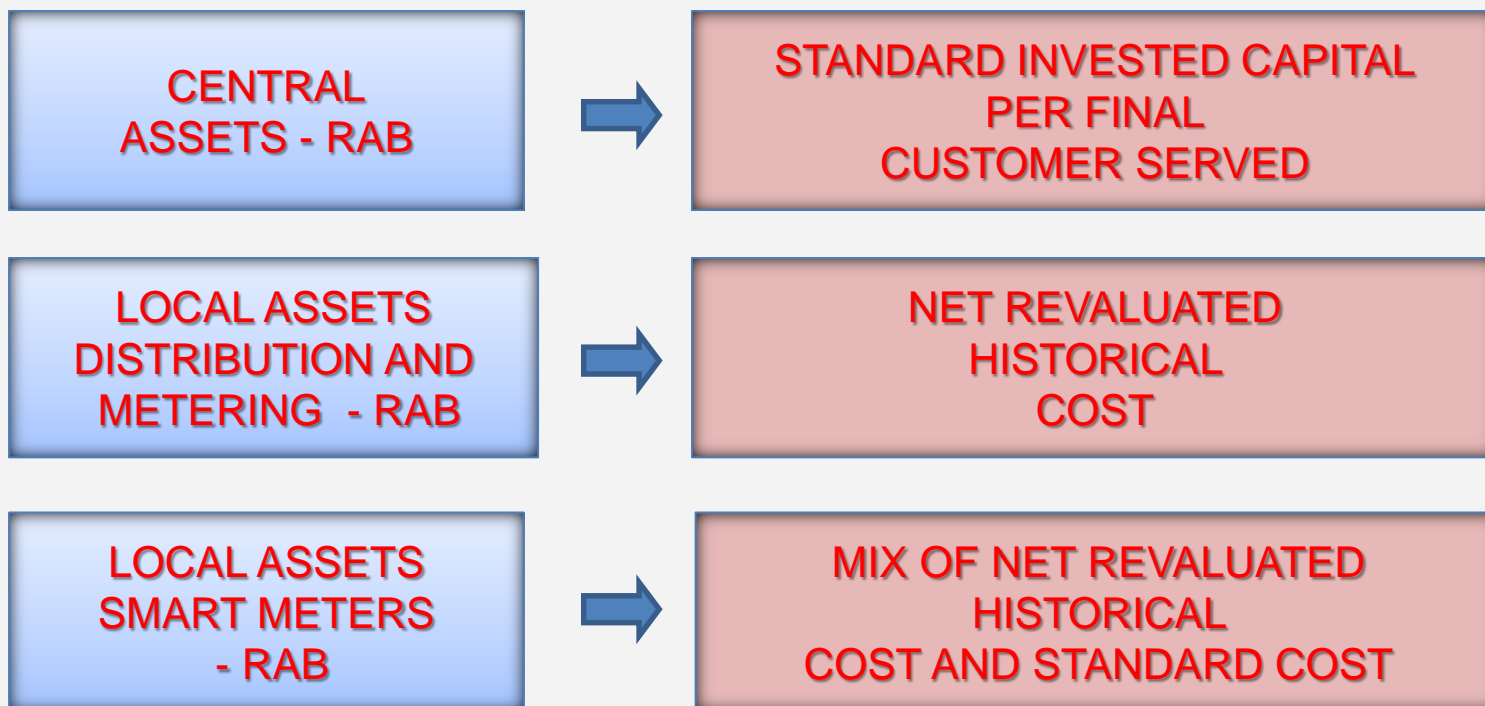
ELECTRICITY DISTRIBUTION – FIXED ASSET CATEGORIES

- **Land**
- **Buildings**
- **EHV-HV lines: 220, 120-150, 40-80 kV***
- **Electric stations: 220*, 120-150, 40-80 kV**
- **Electric sub-stations**
- **Electric sub-stations transformers;**
- **MV lines (from 1 to 35 kV)**
- **LV lines (230-380 V)**

- **Furnitures**
- **Other tangible assets** (Equipment, Vehicles)
- **IT** (remote transmission, pc stations, data processing systems)
- **Intangible assets** (licences, R&D, patent rights and trademarks, third party assets improvements, other intangible assets)

* - mostly owned and operated by TSOs

Fixed assets related to high voltage distribution:

- Historical revaluated cost, calculated for each asset group, identified by the year in which the asset is placed in service and the regulatory lifetime

Fixed assets related to medium and low voltage distribution:

- Asset placed in service before 2008: Historical revaluated cost calculated parametrically

- Asset placed in service after 2007: historical revaluated cost, calculated for each asset group, identified by the year in which the asset is placed in service and the regulatory lifetime

ELECTRICITY DISTRIBUTION - DEPRECIATION

- Depreciation is calculated under a **straight-line** method for each asset included into RAB

- The yearly allowance is calculated as ratio between:
  - **net invested capital**
  - **residual regulatory lifetime** of each assets

- Regulatory assets lifetime has been defined on the basis of technical lifetime

Depreciation is updated on a yearly basis taking into account:

- New net investments depreciation and divestitures depreciation

- Revaluation through gross investment deflator index

ASSETS	TECHNICAL LIFETIME
LAND	NOT DEPRECIATED
BUILDINGS	40
TRANSMISSION AND HV LINES	45
TRANSMISSION STATIONS	33
ELECTRIC SUBSTATIONS	30
MV AND LV LINES	35
FURNITURE	17
OTHE TANGIBLE ASSETS	10
IT	5
INTANGIBLE ASSETS	5
HV AND MV METERS	20
LV SMART METERS	15

GAS DISTRIBUTION - DEPRECIATION

- The yearly allowance for asset depreciation of **local assets** is the ratio between the **gross revaluated historical cost** and the **regulatory life**

- Depreciation for **central assets** is set **parametrically** per customer served

ASSET	REGULATORY LIFE (years)	
	Municipal concessions	**New concessions**
Buildings	40	60
Mains	50	60
Customer connections	40	50
Citygates	20	25
Other tangible assets and intangible assets	7	7
Remote meters	15	15
Concentrators	15	15
Electronic meters	15	15
Traditional meters (>G6)	20	20
Traditional meters (<=G6)	15	15
Volumes converter with a data transmission system	15	15

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REVIEW OF THE ALLOWED RATE OF RETURN METHODOLOGY

- With decision 583/2015/R/com ARERA reformed the criteria for the determination and updating of the allowed rate of return in the electricity and gas sectors.

- The previous allowed rate of return methodology adopted by ARERA was first introduced in the second electricity transmission and distribution regulatory period (2004).

- At the time, yields on Italian government bonds were a reasonable proxy for risk-free rates and it was generally assumed that market risk premium and interest rates were non correlated.

- Since the start of the global financial crisis (2008), a number of unusual events have affected capital markets and macroeconomic condition across the globe, including the Eurozone countries.

- ARERA found it necessary to review the previous allowed rate of return methodology also to avoid that different market conditions at the time of the tariff revision could lead to unjustified differentiations of allowed returns among regulated services.
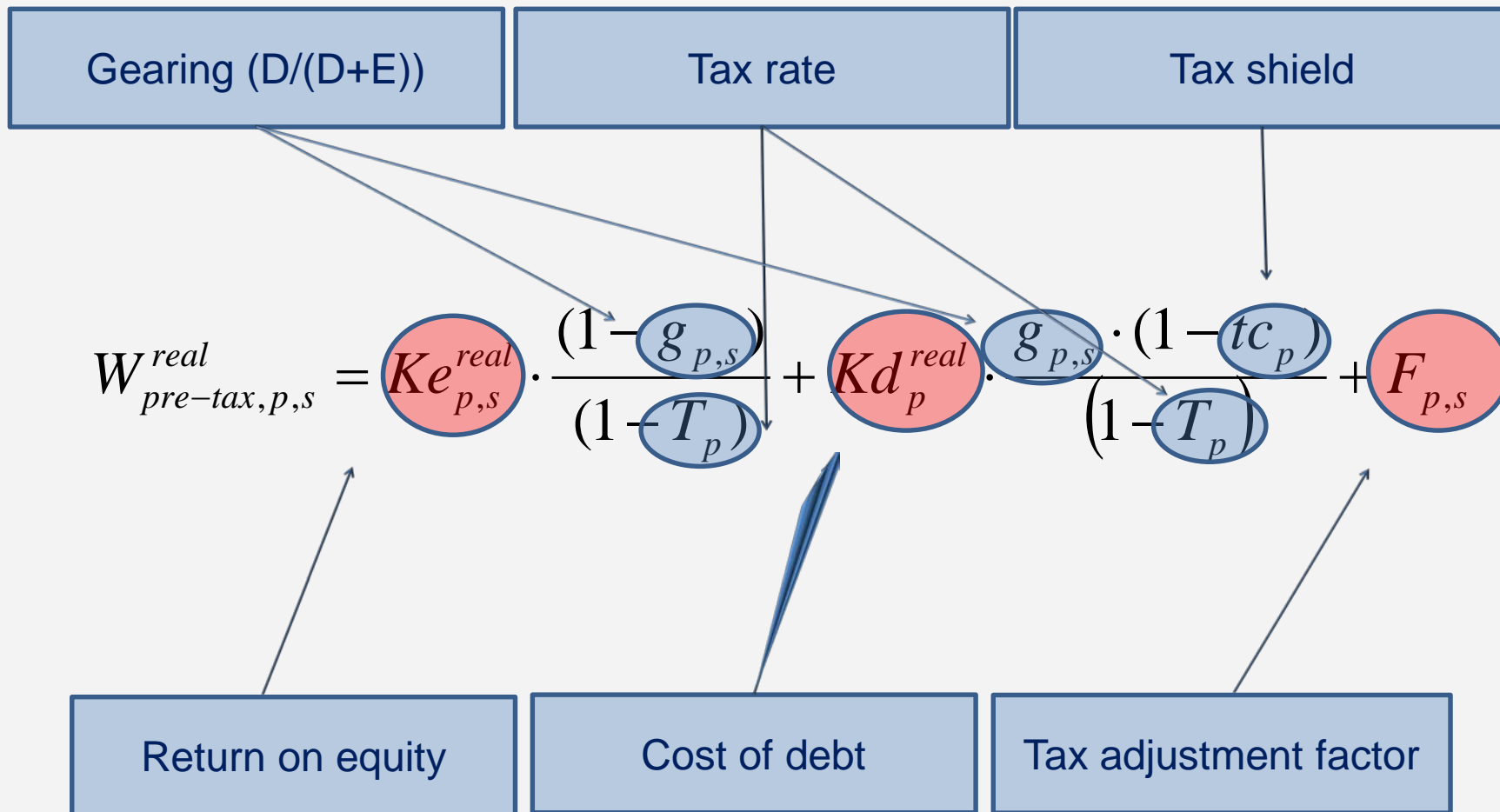
GENERAL APPROACH

Decision 597/2014/R/COM stated the general approach to be followed in the allowed rate of return calculation methodology review:

- the allowed rate of return is calculated as a **weighted average cost of capital (WACC)**

- the allowed rate of return is calculated as *real* and *pre-tax*

- the cost of equity is calculated according to the *Capital Asset Pricing Model (CAPM)*

WACC REGULATORY PERIOD (*PWACC*)

- ARERA intended to unify the WACC parameters, except *β* and gearing, for **all the regulated activities of electricity and gas sectors**.

- Unified WACC parameters are set by ARERA for a period of time, called **WACC regulatory period** (*PWACC*).

- The length of the 'WACC regulatory period' is **six years**. The *PWACC* consists of **two sub-periods**, each one lasting three years.

- In the interim PWACC review are reviewed the following parametrs:
  - risk-free rate;
  - Country Risk Premium;
  - inflation rate;
  - fiscal parameters.

WACC FORMULATION

Gearing (D/(D+E))

Tax rate

Tax shield

$$W^{real}_{pre-tax,p,s} = Ke^{real}_{p,s} \cdot \frac{(1-g_{p,s})}{(1-T_p)} + Kd^{real}_p \cdot \frac{g_{p,s} \cdot (1-tc_p)}{(1-T_p)} + F_{p,s}$$

Return on equity

Cost of debt

Tax adjustment factor

COST OF EQUITY

The cost of equity is calculated adding to the traditional CAPM formulation a specific term reflecting the **Country Risk Premium (CRP)**

$$K_e = RF + \beta \cdot ERP + CRP$$

where:
- RF is the risk-free rate
- β is a measure of the systematic risk of an activity
- ERP is the equity risk premium

The introduction of parameter *CRP* allows to explicitly capture the impact of the fiscal crisis on required returns for regulated utilities in Italy

POST TAX RETURN ON EQUITY

$$Ke_{p,s}^{real} = \max\left(\frac{RF_p^{no\min al} - isr_p}{1 + isr_p};0,005\right) + \beta_s^{asset} \cdot \left[1 + (1 - tc_p) \cdot \frac{g_{p,s}}{1 - g_{p,s}}\right] \cdot ERP_p + CRP_p$$

Risk-free rate

Beta levered

Country Risk Premium

Equity Risk Premium

$$ERP_p = TMR - \max\left(\frac{RF_p^{no\min al} - isr_p}{1 + isr_p};0,005\right)$$

where:
isr$_p$ is the expected inflation rate.

TOTAL MARKET RETURN (TMR)

In the new approach a greater weight was placed on the concept of total equity market return, to ensure a consistent set of assumptions for the risk-free rate and the equity risk premium, rather than estimating them separately

TMR was estimated on the basis of long term evidences:
- time horizon: 1900-2014
- countries considered in the calculation: Belgium, France, Germany and Netherlands (rated at least "AA")
- weighted average of the arithmetic (6,6%) and geometric (3,5%) averages

Range of the weight of arithmetic average doc. 509/2015

50%   80%

TMR   5,1%   6,0%
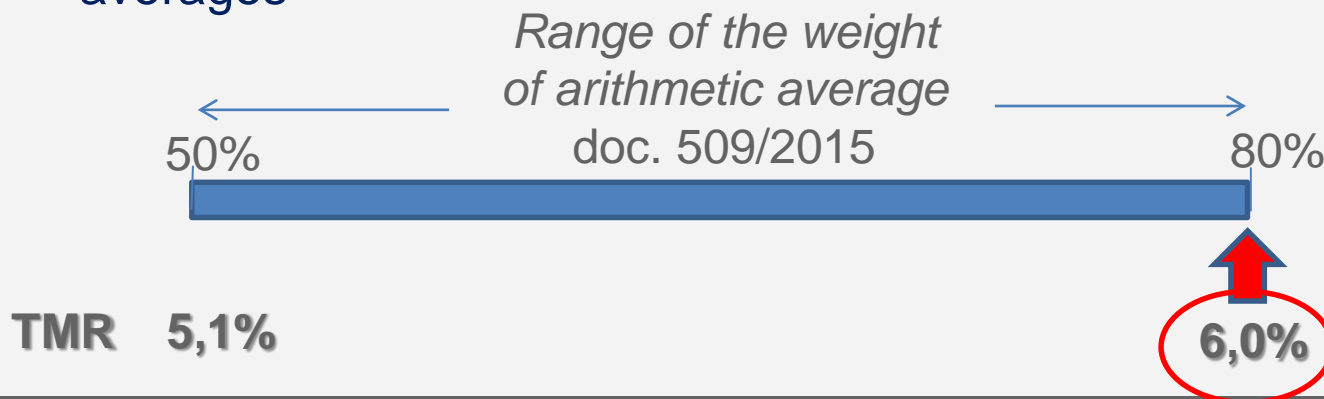
REAL RISK-FREE RATE

Nominal risk-free rate:
average of nominal ten-year benchmark government bond yields in Eurozone countries with minimum rating "AA" (Belgium, France, Germany and Netherlands) in the period 1 October 2014 – 30 September 2015

0,79%

Real risk-free rate **- 0,6%**

Floor: +0,5%

Inflation rate:
average of ten-year inflation linked swap rate in the period 1 October 2014 – 30 September 2015

1,39%

In order to avoid negative yields, not consistent with economic expectations, ARERA introduced a ***floor*** for the real risk-free rate. On this basis, the real risk-free rate was set equal to **0,5%** for years 2016-2018.

EQUITY RISK PREMIUM (ERP)

AEEGSI adopted a **'TMR constant'** approach, according to which the ERP is calculated as the difference between TMR and RF.

+TMR	**5,1%**	**6,0%**
- RF	**0,5%**	**0,5%**
= ERP	**4,6%**	**5,5%**

Range doc. 509/2015

Final decision
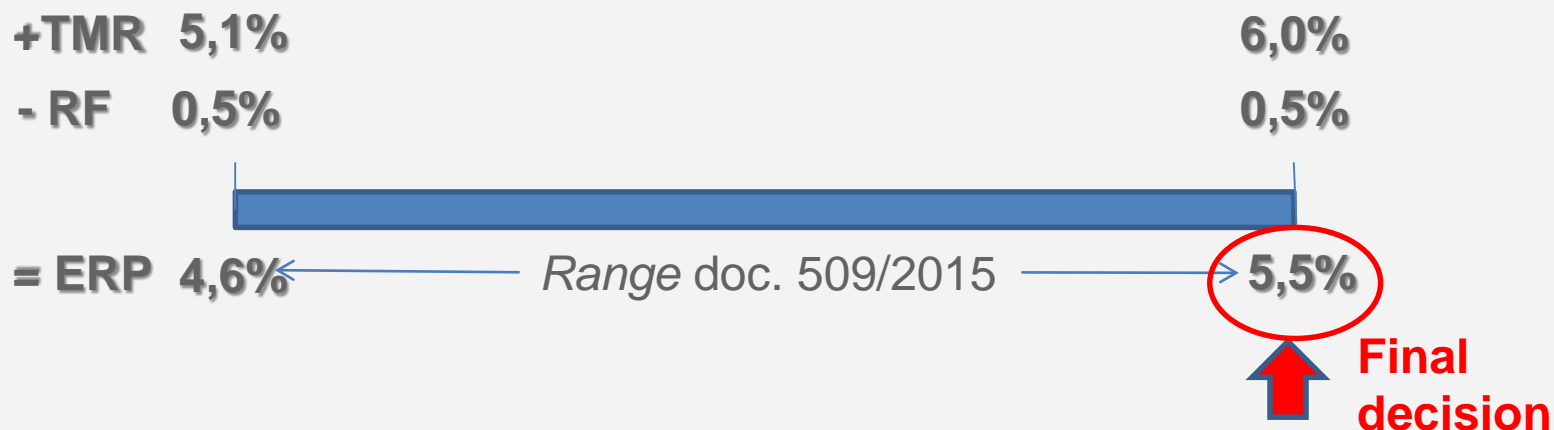
The approach followed for the setting of the risk-free rate and of the equity risk rate allows to reflect "normal" market conditions, before considering the impact of the fiscal crisis in Italy on required returns

COUNTRY RISK PREMIUM

CRP reflects the compensation investors require to operate in a certain country.

Rating differentials among countries affect also companies ratings. *CRP* affects both cost of debt and cost of equity.

Two approaches to estimate *CRP* can be followed:

- evidence from **corporate debt markets**
- evidence from **equity markets**

According to initial evaluations *CRP* was estimated to vary between 0,5% and 1,0%.

In the final decision ARERA set *CRP* equal to **1,0%** for years 2016-2018 for both equity and debt.

COST OF DEBT

From a theoretical point of view, cost of debt can be estimated adding to RF a spread determined on the basis of debt β. The implementation of this approach, however, presents some practical difficulties.

ARERA examined the structure and the stratification of regulated companies' medium and long term debt.

ARERA set the cost of debt in order to reflect the cost of efficiently incurred debt, considering the economic sustainability, giving incentive to define efficient debt portfolios and taking into account evidences from capital markets.

$$Kd_p^{real} = \max\left(\frac{RF_p^{no\,minal} - isr_p}{1 + isr_p}; 0{,}005\right) + CRP_p + DRP$$
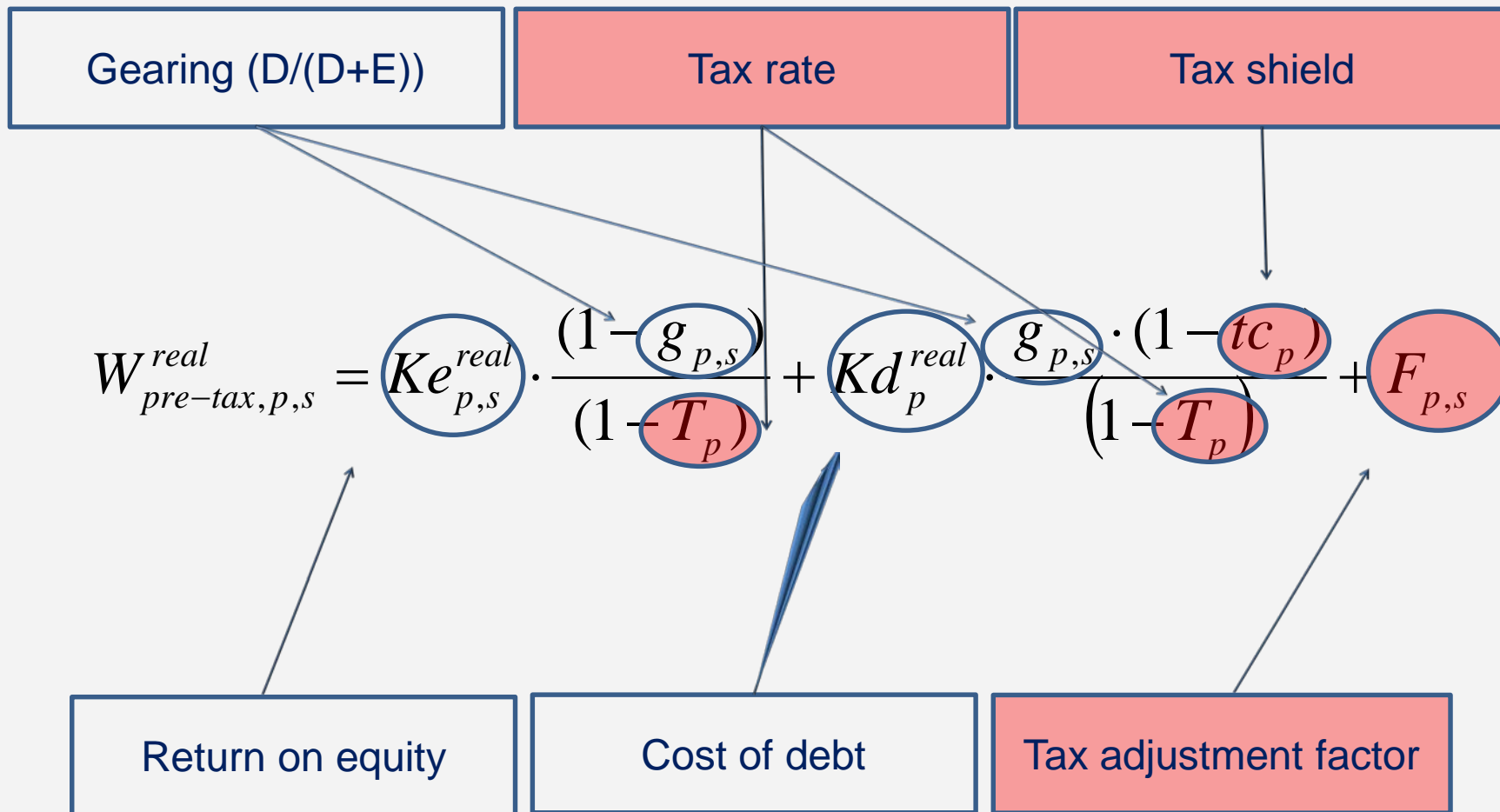
Risk-free rate   **Country Risk Premium**   **Debt Risk Premium**

FISCAL PARAMETERS

Gearing (D/(D+E))	Tax rate	Tax shield

$$W_{pre-tax,p,s}^{real} = Ke_{p,s}^{real} \cdot \frac{(1-g_{p,s})}{(1-T_p)} + Kd_p^{real} \cdot \frac{g_{p,s} \cdot (1-tc_p)}{(1-T_p)} + F_{p,s}$$

Return on equity	Cost of debt	Tax adjustment factor

Fiscal parameters in the WACC formulation allow to take into consideration:

- the effect of the tax rate on the return on equity and on the cost of debt (parameter T)
- the effect of tax shield on the cost of debt (parameter tc)
- the fact that taxes are paid on nominal returns (tax adjustment factor)

ACTIVITY SPECIFIC PARAMETERS

ARERA decided to estimate specific **β** for each regulated activity, considering evidences coming from the Eurozone equity markets related to companies with high credit rating, in a period of at least two years.

In ARERA's opinion **β** estimate cannot be considered as a pure mechanistic exercise. It is necessary to analyse the results and evaluate the coherence with the general regulatory framework evolution.

ARERA decided to set the **gearing** level taking into account the actual levels for regulated companies and considering the perspective of a gradual alignment towards the average levels adopted by other regulators.

GEARING: INTERIM REVIEW

For the second sub-period beginning in year 2019 ARERA, in the perspective of a gradual convergence towards the levels adopted by other european regulators, envisaged a revision of gearing level for all regulated activities, with a maximum level of 0,5.

The revision of gearing implies, as a consequence, also a revision of beta levered, on the basis of the following formula:

$$\beta^{levered} = \beta^{asset} \cdot \left(1 + (1 - tc) \cdot \frac{D}{E} \right)$$

In the final decision ARERA adopted a trigger approach for the review of the CRP, based on the following formula:

$$CRP_{II} = CRP_{I} \cdot \left[1 + \left(\frac{Spread^{corr}}{Spread^{base}} - 1 \right) \cdot SC \right]$$

where:

- $Spread^{corr}$ is the average spread between the Italian ten-year BTP benchmark and the German ten-year Bund in the period 1 October 2017 - 30 September 2018 **1,4%**
- $Spread^{base}$ is the average spread between the Italian ten-year BTP benchmark and the German ten-year Bund in the period 1 October 2014 - 30 September 2015
- SC is a dummy variable equal to 0 if the difference between $Spread^{corr}$ and $Spread^{base}$ (in absolute terms) is ≤ 20% and equal to 1 else

MID-PERIOD REVIEW: OTHER PARAMETERS

Other parameters will be reviewed as follows:

- the risk-free rate will be calculated on the basis of the following formula:

$$RF_{II}^{real} = \max\left(\frac{RF_{II}^{no\,minal} - isr_{II}}{1 + isr_{II}} ; 0,005 \right)$$

where:

$RF_{II}^{no\,minal}$ is the average of yields on government bonds issued by Eurozone countries rated at least "AA" in the period 1 October 2017 – 30 September 2018

0,5%

isr_{II} is the average of ten-year inflation linked swap rates in the Eurozone in the period 1 October 2017 – 30 September 2018

- the parameter ERP_p will be recalculated as the difference between the TMR (set equal to 6,0%) and the risk-free rate

5,5%

- the parameter ia_p will be defined on the basis of the most recent forecasts of the ECB

1,7%

- parameters T_p and tc_p will be defined on the basis of a detailed analysis in order to estimate taxation levels.
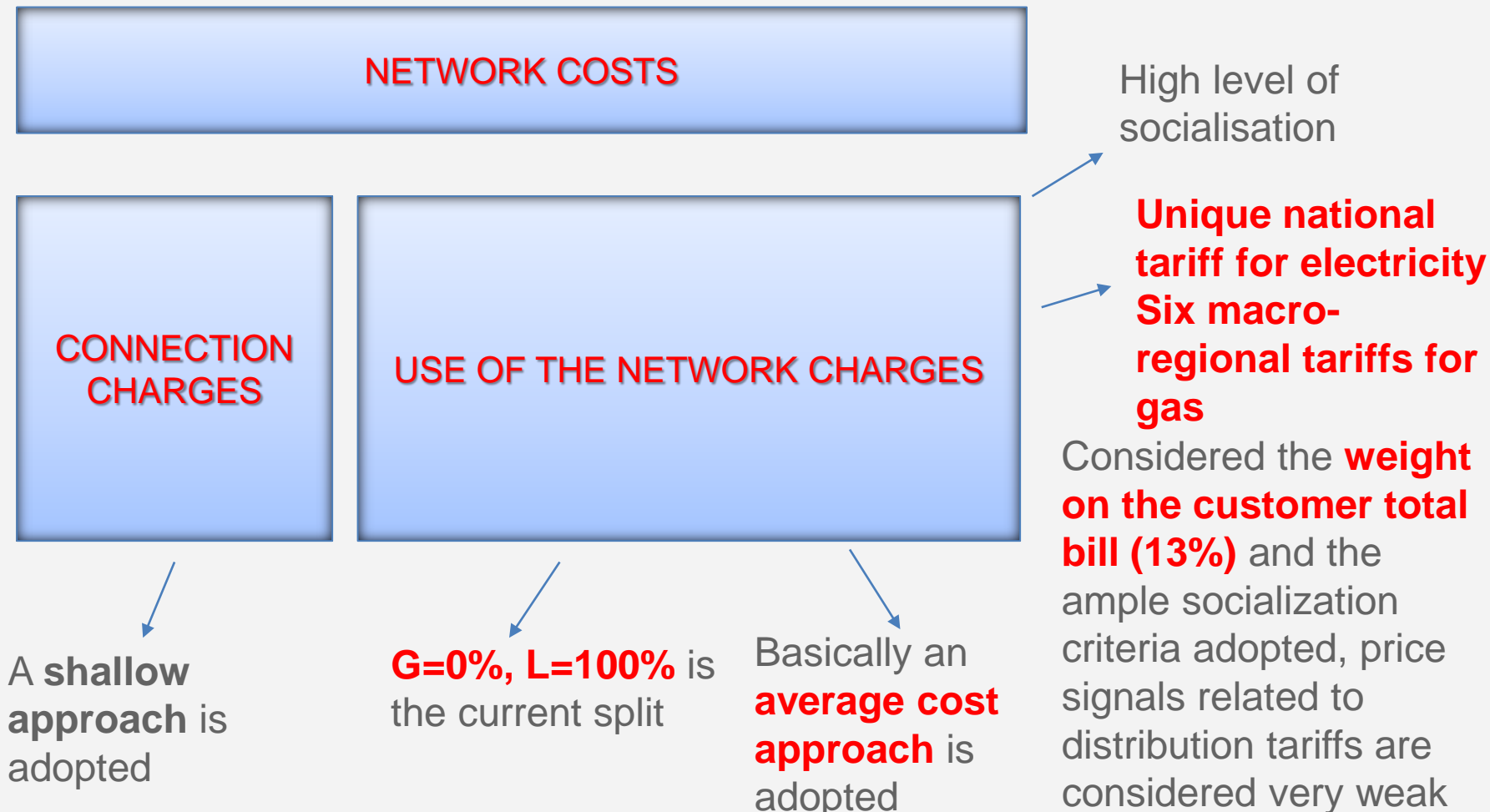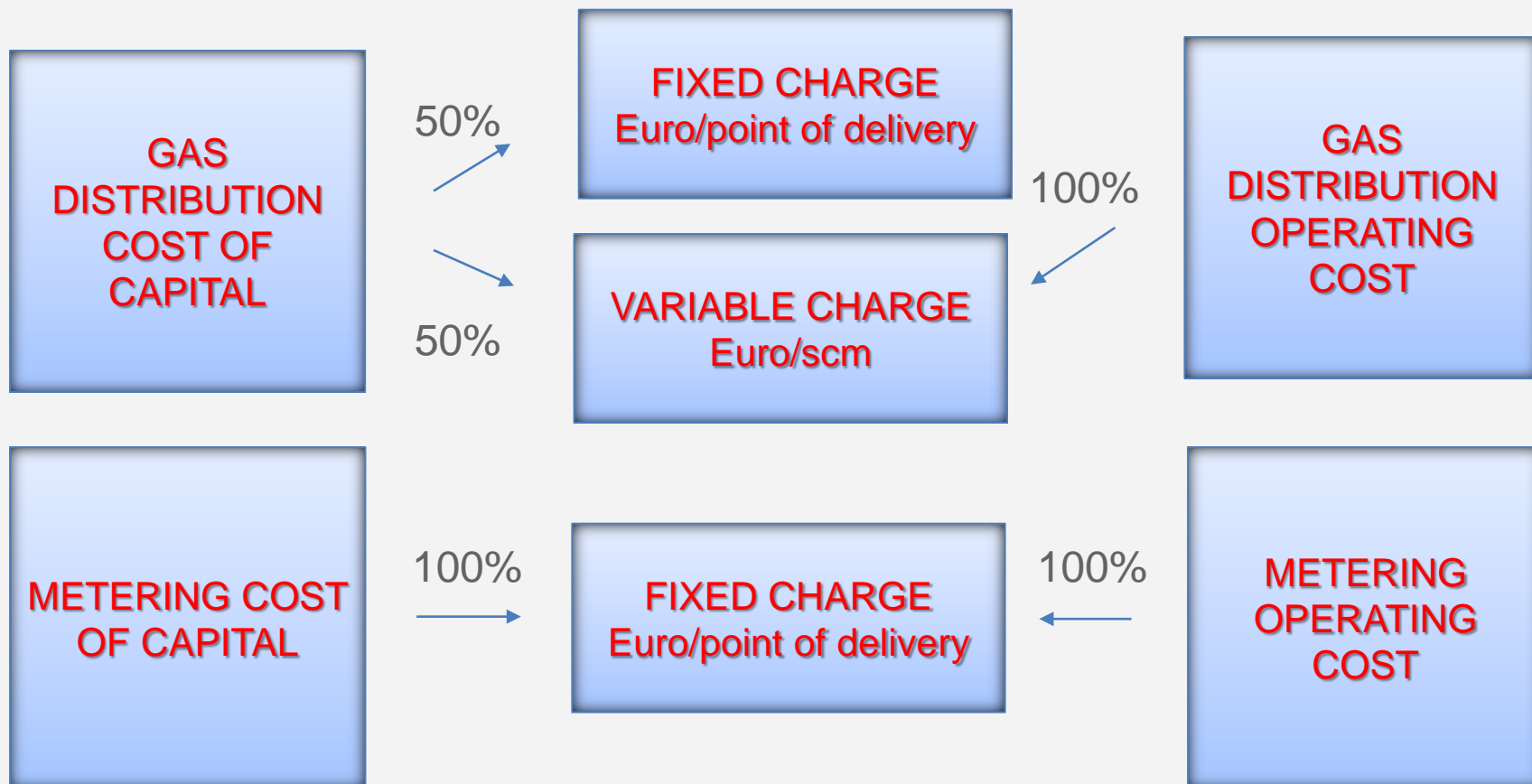
31% **24%**

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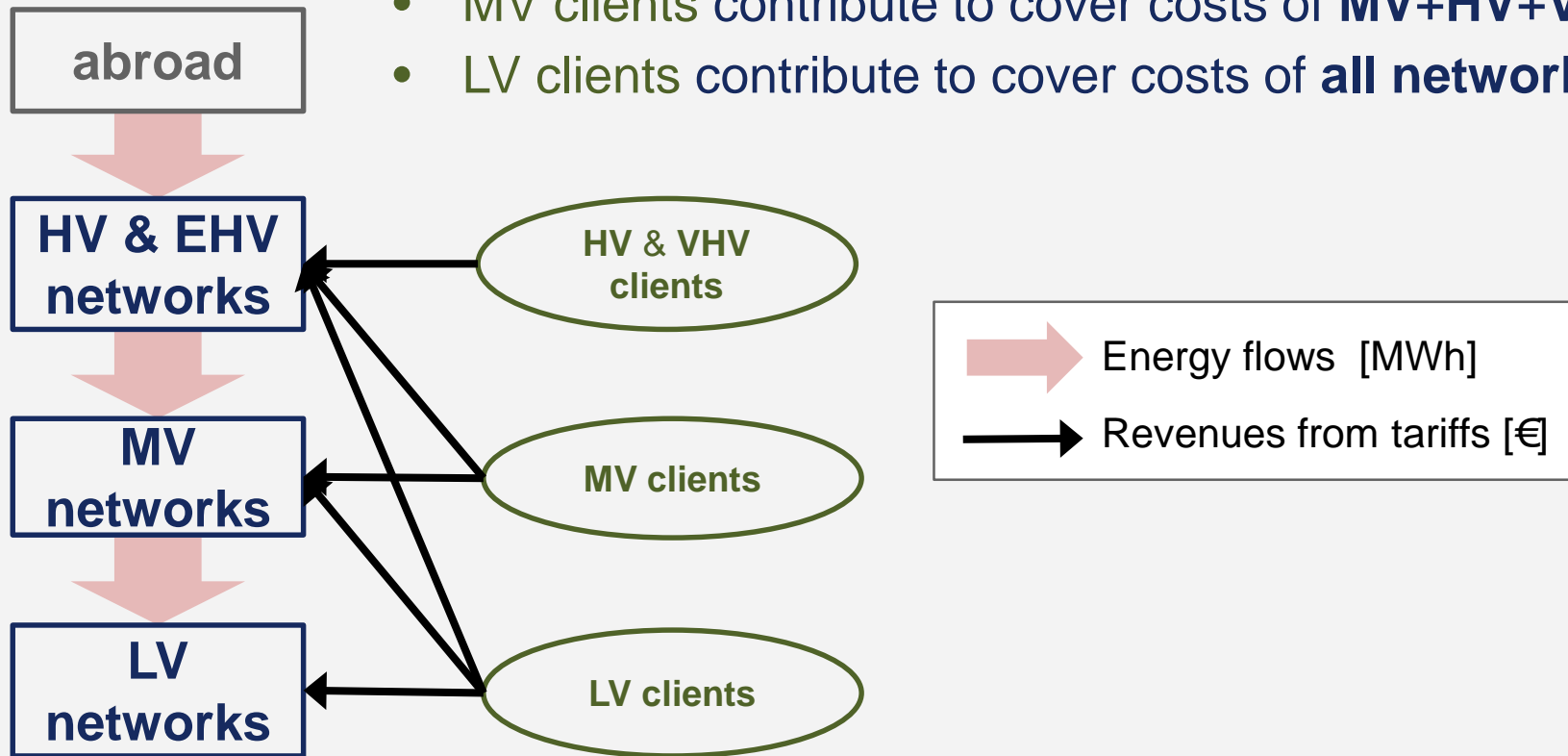
6. The new challenges

COST ALLOCATION- GENERAL APPROACH

NETWORK COSTS

CONNECTION CHARGES

USE OF THE NETWORK CHARGES

High level of socialisation

Unique national tariff for electricity Six macro-regional tariffs for gas

Considered the **weight on the customer total bill (13%)** and the ample socialization criteria adopted, price signals related to distribution tariffs are considered very weak

A **shallow approach** is adopted

G=0%, L=100% is the current split

Basically an **average cost approach** is adopted

GAS DISTRIBUTION COST OF CAPITAL

50% → FIXED CHARGE Euro/point of delivery

50% → VARIABLE CHARGE Euro/scm

100% ← GAS DISTRIBUTION OPERATING COST

METERING COST OF CAPITAL

100% → FIXED CHARGE Euro/point of delivery

100% ← METERING OPERATING COST

So far, the cost of each network has been covered by clients connected to the same or to lower voltage levels.   This means that:

- HV clients contribute to cover costs of **HV+VHV networks**,
- MV clients contribute to cover costs of **MV+HV+VHV nets,**
- LV clients contribute to cover costs of **all networks.**

Energy flows [MWh]

Revenues from tariffs [€]

- Tariffs paid by final customers are differentiated per tariff area.
- In particular, 6 tariff areas have been defined, corresponding to aggregations of Regions.
- The tariff in each area reflects the cost of service in the tariff area.
- Since year 2015 fixed components are differentiated on the basis of the class of the meter, distinguishing between:
  - meter class <= G6;
  - meter class > G6 and <= G40;
  - meter class >G40.
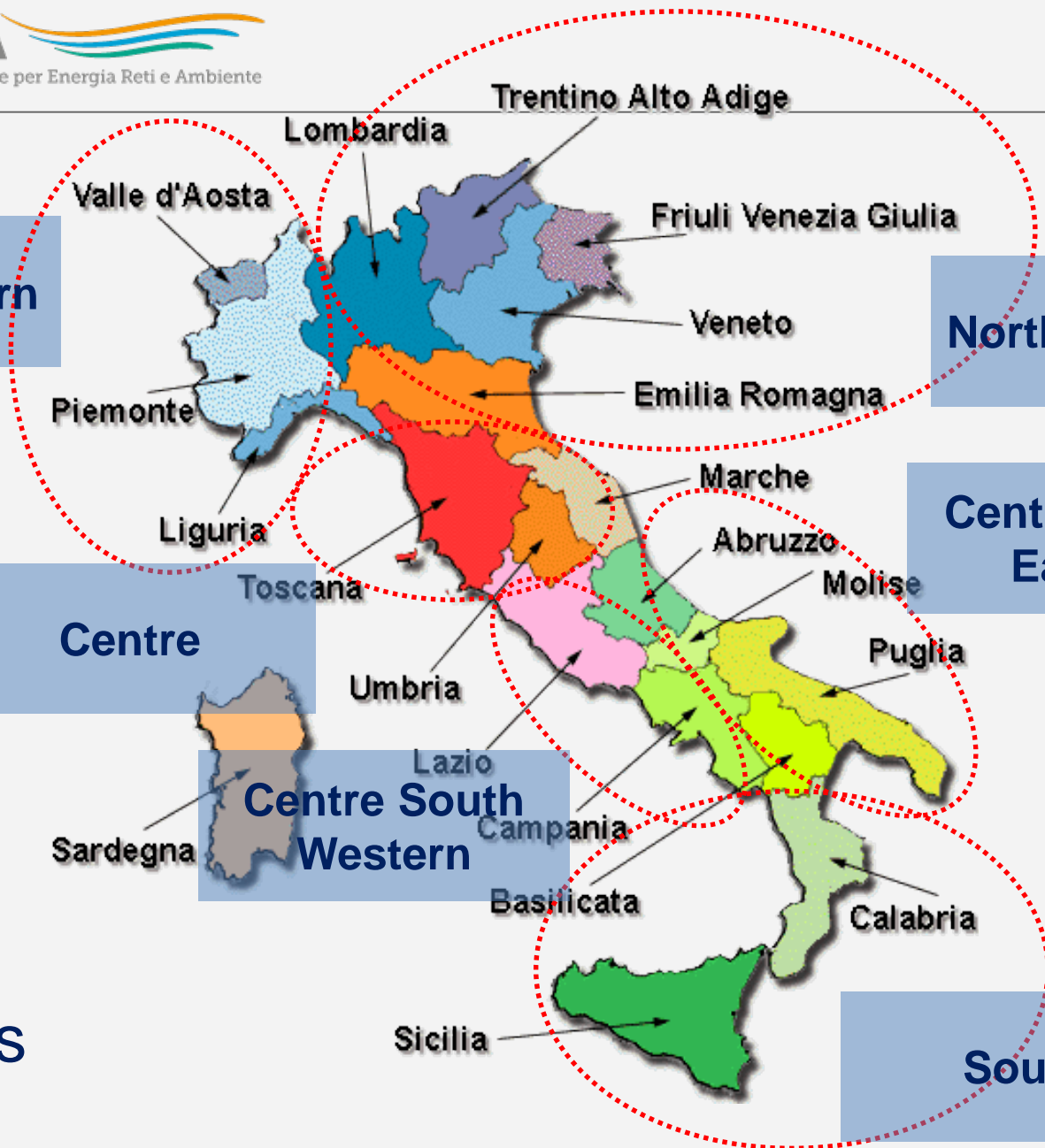
Tariff areas

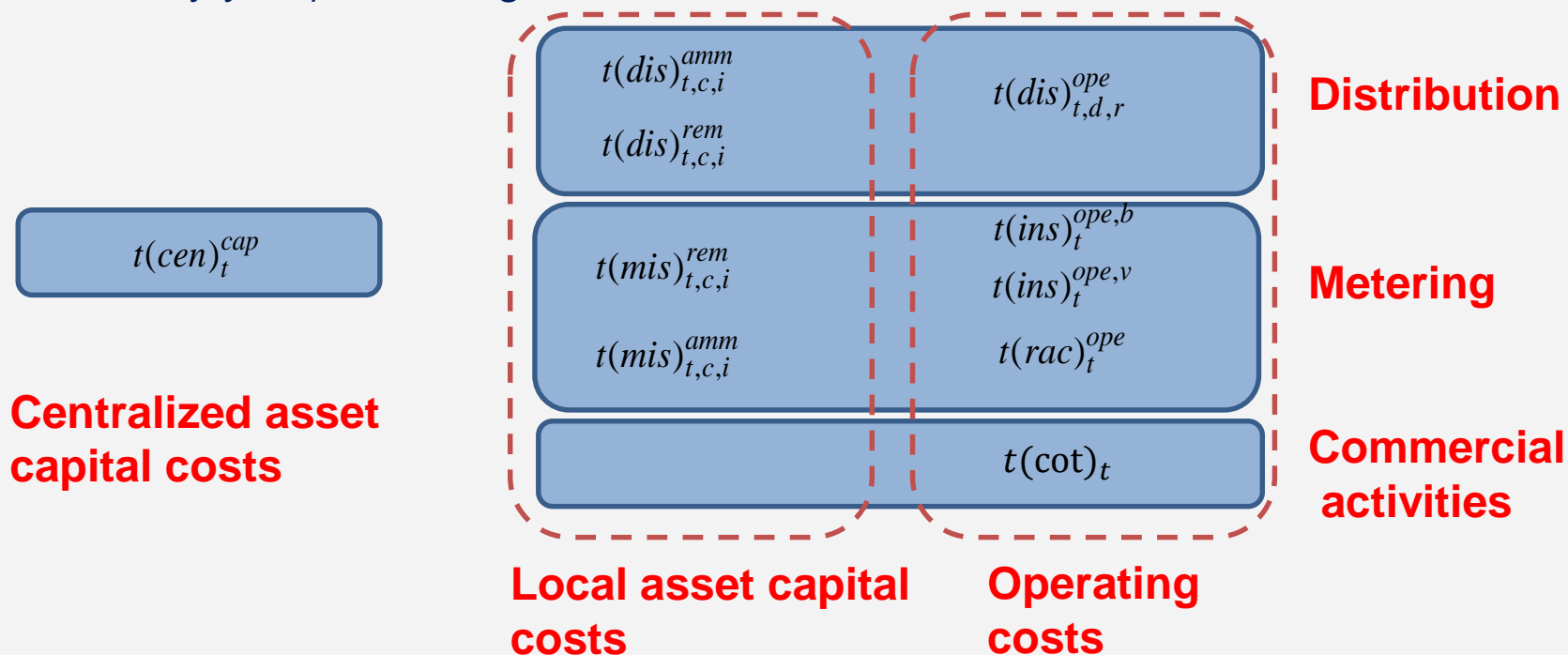# GAS DISTRIBUTION – STRUCTURE OF VARIABLE CHARGE

- Variable charges $\tau_3^f(dis)$, differentiated per tariff area, are calculated on the basis of a **national tariff articulation** and of the specific costs incurred in each tariff area

- The national tariff articulation is in principle **degressive**, in order to reflect costs

- The **first band of consumption**, for **social reasons**, has been set equal to zero

National tariff articulation

Consumption band (scm/year)	eurocent/scm
0-120	0,00
121-480	7,79
481-1,560	7,13
1,561-5,000	7,16
5,001-80,000	5,35
80,001-200,000	2,71
200,001-1,000,000	1,33
More than 1,000,000	0,37

- Allowed revenues are calculated on the basis of the **reference tariff** and the **relevant scale variables**
- The reference tariff is a vector of **fixed charges** (expressed in €/point of delivery/year) reflecting different cost elements.

$$t(cen)_t^{cap}$$

Centralized asset capital costs

$$t(dis)_{t,c,i}^{amm}$$
$$t(dis)_{t,c,i}^{rem}$$

$$t(dis)_{t,d,r}^{ope}$$

Distribution

$$t(mis)_{t,c,i}^{rem}$$
$$t(mis)_{t,c,i}^{amm}$$

$$t(ins)_t^{ope,b}$$
$$t(ins)_t^{ope,v}$$
$$t(rac)_t^{ope}$$

Metering

$$t(cot)_t$$

Commercial activities

Local asset capital costs

Operating costs

ELECTRICITY – DISTRIBUTION TARIFF FOR FINAL CUSTOMERS

CLASS OF NETWORK USERS	METERING COSTS	DISTRIBUTION NETWORK COSTS	COMMERCIAL COSTS
LV HOUSEHOLDS	FIXED CHARGE	CAPACITY CHARGE, ENERGY CHARGE	FIXED CHARGE
LV PUBLIC RECHARGING OF ELECTRICAL VEHICLES	ENERGY CHARGE	ENERGY CHARGE	ENERGY CHARGE
LV PUBLIC LIGHTING	ENERGY CHARGE	ENERGY CHARGE	ENERGY CHARGE
LV OTHER USES	FIXED CHARGE	CAPACITY CHARGE, ENERGY CHARGE	FIXED CHARGE
MV PUBLIC LIGHTING	ENERGY CHARGE	ENERGY CHARGE	ENERGY CHARGE
MV OTHER USES	FIXED CHARGE	CAPACITY CHARGE, ENERGY CHARGE	FIXEX CHARGE
HV	FIXED CHARGE	ENERGY CHARGE	
EHV	FIXED CHARGE		
GENERATORS	NO G-CHARGE TARIFF AT ANY VOLTAGE LEVEL		

UNIQUE NATIONAL TARIFF

ELECTRICITY – REFERENCE TARIFF

- Allowed revenues for each DSO are calculated on the basis of the **reference tariff** (calculated for each DSO) and the **relevant scale variables** (Point of delivery served for fixed charge and energy served for energy charge).

- The reference tariff are differentiated by class of final users and have a **fixed charge**, expressed in €/point of delivery/year and an **energy charge**, expressed in €/kWh .

TOPICS

1. Introduction

2. Allowed cost calculation

3. Rate of return calculation method

4. Cost allocation approach

5. Tariffs structure

6. The new challenges

THE NEW CHALLENGES

EU ENERGY POLICY OBJECTIVES – GREEN PACKAGE

TECHNOLOGICAL DEVELOPMENT

DECARBONISATION

ENERGY EFFICIENCY

RENEWABLES
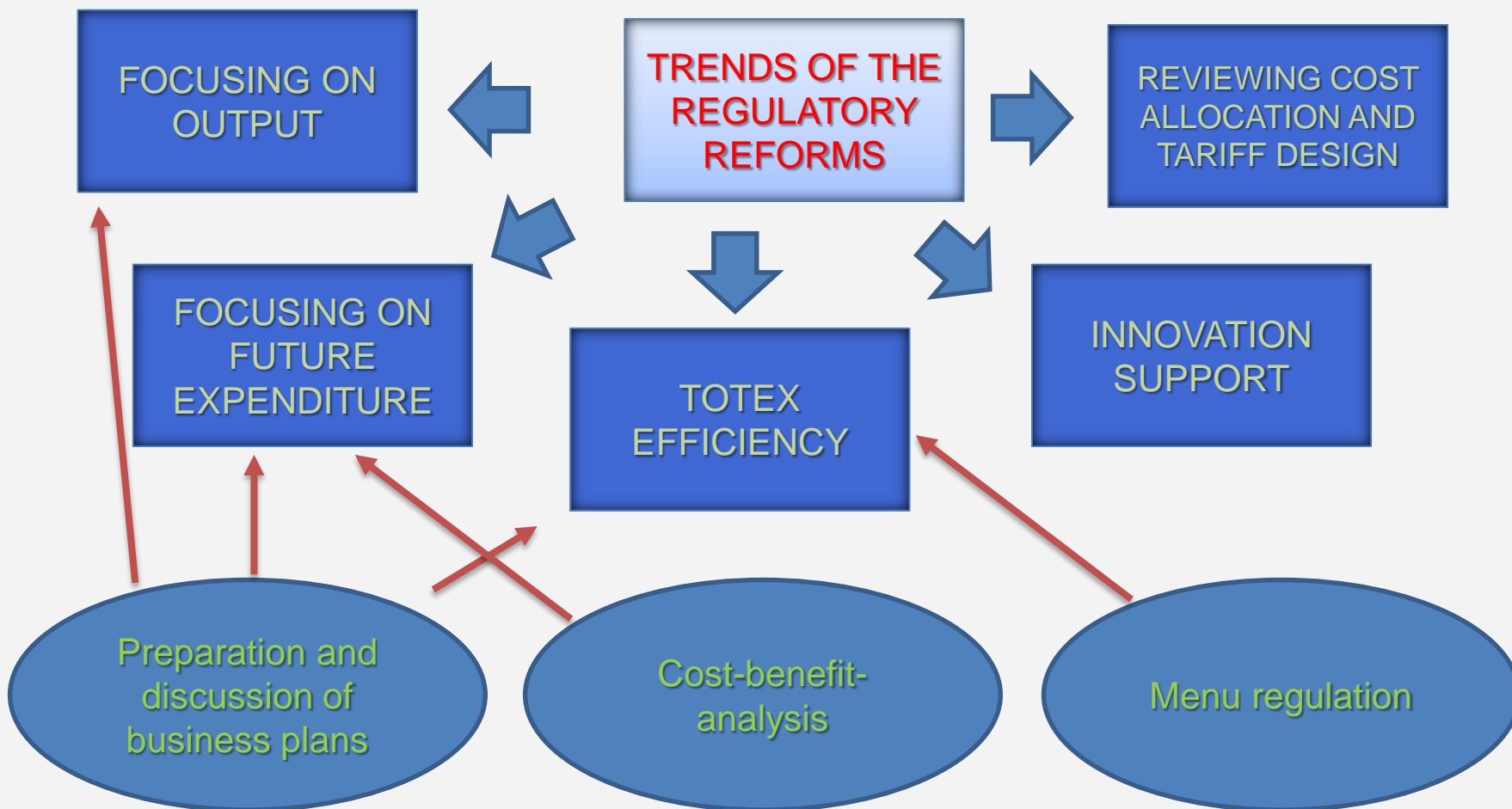
DIGITALIZATION

DISTRIBUTED GENERATION

DEMANDE RESPONSE

SMART GRID

SMART METER

AND THE REGULATORS?

ADAPTING THE REGULATORY TOOLKIT

FOCUSING ON OUTPUT

TRENDS OF THE REGULATORY REFORMS

REVIEWING COST ALLOCATION AND TARIFF DESIGN

FOCUSING ON FUTURE EXPENDITURE

TOTEX EFFICIENCY

INNOVATION SUPPORT

Preparation and discussion of business plans

Cost-benefit-analysis

Menu regulation

TOTEX APPROACH - 1

- ARERA proposed in DCO 5/2015 the adoption of a new approach based on total expenditure (*totex*)

- *Totex* approach is considered by ARERA more efficient compared to the present hybrid approach (*price cap* applied to operating costs and cost of service regulation applied to capital costs)

- In the new regulatory strategic framework approved with the **decision 242/2019/A (June 2019)** the totex approach has been integrated in a more comprehensive **regulation by objectives of service and expenditure approach (ROSS)**

TOTEX APPROACH - 2

- DCO 335/2015 outlines the key features of *totex* approach:
    - focus on future expenditure;
    - output orientation;
    - stronger incentive to improve total productivity.

- The adoption of a *totex* approach implies giving more relevance to forecast and business plans. Due to information asymmetry, it is therefore necessary to introduce *truth telling* incentives in order to obtain credible business plans from regulated companies.

- *Totex* are generally managed with menus, aimed at combining productivity incentives and truth telling incentives.

- Cost assessment and total expenditure analysis play a key role in the implementation of *totex*.

- The adoption of *totex* requires also to strengthen enforcement, in order to control the actual level of outputs and of expenditure.
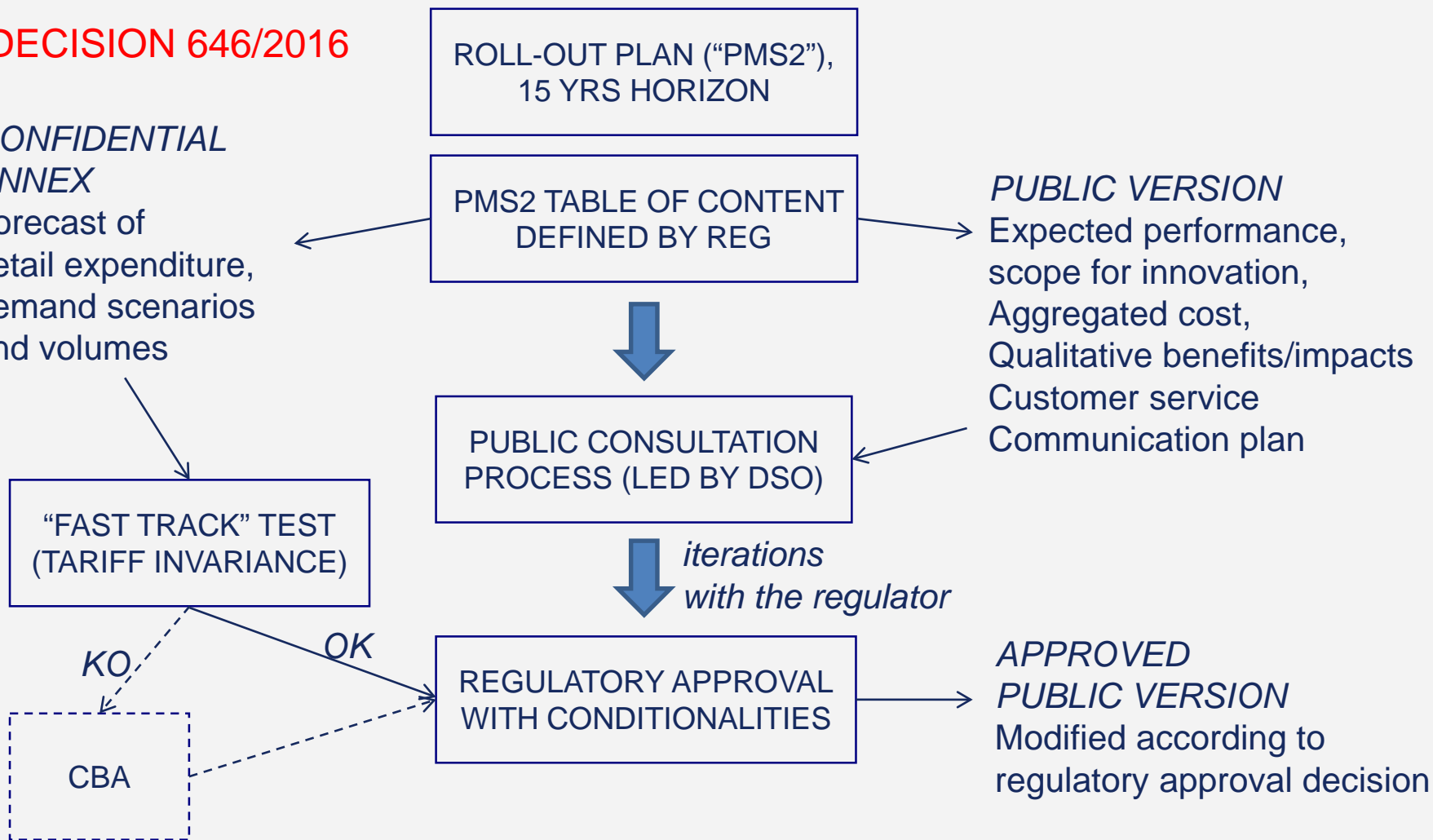
DECISION 646/2016

ROLL-OUT PLAN ("PMS2"),
15 YRS HORIZON

CONFIDENTIAL ANNEX
Forecast of
detail expenditure,
demand scenarios
and volumes

PMS2 TABLE OF CONTENT
DEFINED BY REG

PUBLIC VERSION
Expected performance,
scope for innovation,
Aggregated cost,
Qualitative benefits/impacts
Customer service
Communication plan

"FAST TRACK" TEST
(TARIFF INVARIANCE)

PUBLIC CONSULTATION
PROCESS (LED BY DSO)

*iterations
with the regulator*

KO

OK

CBA

REGULATORY APPROVAL
WITH CONDITIONALITIES

*APPROVED
PUBLIC VERSION*
Modified according to
regulatory approval decision

Ratio DSO/NRA estimation		0.75	0.80	0.85	0.90	0.95	1.00	1.05	1.10	1.15	1.20	1.25
"Admissible" expenditures		93.75	95.00	96.25	97.50	98.75	100.00	101.25	102.50	103.75	105.00	106.25
Efficiency Incentive coeff.		26.25%	25.00%	23.75%	22.50%	21.25%	20.00%	18.75%	17.50%	16.25%	15.00%	13.75%
Information Incentive		0.86	0.75	0.61	0.44	0.23	0.00	-0.27	-0.56	-0.89	-1.25	-1.64
Expenditure estimation (NRA)		100	100	100	100	100	100	100	100	100	100	100
Expenditure estimation (DSO)		75	80	85	90	95	100	105	110	115	120	125
Actual expenditure	75	5.78	5.75	5.66	5.50	5.28	5.00	4.66	4.25	3.78	3.25	2.66
	80	4.47	4.50	4.47	4.38	4.22	4.00	3.72	3.38	2.97	2.50	1.97
	85	3.16	3.25	3.28	3.25	3.16	3.00	2.78	2.50	2.16	1.75	1.28
	90	1.84	2.00	2.09	2.13	2.09	2.00	1.84	1.63	1.34	1.00	0.59
	95	0.53	0.75	0.91	1.00	1.03	1.00	0.91	0.75	0.53	0.25	-0.09
	100	-0.78	-0.50	-0.28	-0.13	-0.03	0.00	-0.03	-0.13	-0.28	-0.50	-0.78
	105	-2.09	-1.75	-1.47	-1.25	-1.09	-1.00	-0.97	-1.00	-1.09	-1.25	-1.47
	110	-3.41	-3.00	-2.66	-2.38	-2.16	-2.00	-1.91	-1.88	-1.91	-2.00	-2.16
	115	-4.72	-4.25	-3.84	-3.50	-3.22	-3.00	-2.84	-2.75	-2.72	-2.75	-2.84
	120	-6.03	-5.50	-5.03	-4.63	-4.28	-4.00	-3.78	-3.63	-3.53	-3.50	-3.53
	125	-7.34	-6.75	-6.22	-5.75	-5.34	-5.00	-4.72	-4.50	-4.34	-4.25	-4.22

REVIEWING COST ALLOCATION CRITERIA - 1

- Rebalancing the G&L split? G>=0%?
- Review of the approach to connection charges? Adoption of a deep approach instead of a shallow approach? Connection charges based on LRMC?

NETWORK COSTS

CONNECTION CHARGES	USE OF THE NETWORK CHARGES

- Use of the network charges: how to decline the principle of cost reflectivity?

  A strict *short run marginal cost approach* combined with *Ramsey pricing* in order to guarantee revenue collection (assuming the absence of transfers from the State)?

  This approach would be consistent with economic theory, but the implementation of Ramsey pricing could produce relevant redistributive effects

- **Use of the network charges**: to what extent costs have to be socialized?

    The costs of gas and electricity distribution grid have always been socialized in order to reduce price discrimination.

    Socialization is to a certain extent a necessity since network companies anticipate investments in order to satisfy at lower costs the future demand, since the lumpiness of investments in the grid and since the administrative costs of setting an individual tariff would be very high and probably not proportionate to the benefits coming from perfectly tailored tariffs for each customer.

    Is an ample socialization of costs compatible with the development of effective demande response mechanisms?

    Is nodal pricing viable for distribution networks?

- How to respect the universal service obligation?

  Optimal linear pricing as a response to the problems connected with nonnegligilble fixed premium (with potential exclusion of customers with low incomes whose welfare is given substantial weight in the social welfare function)?

  Specific fuel poverty support schemes (in Italy we have specific «bonus» for gas and electricity final customers)
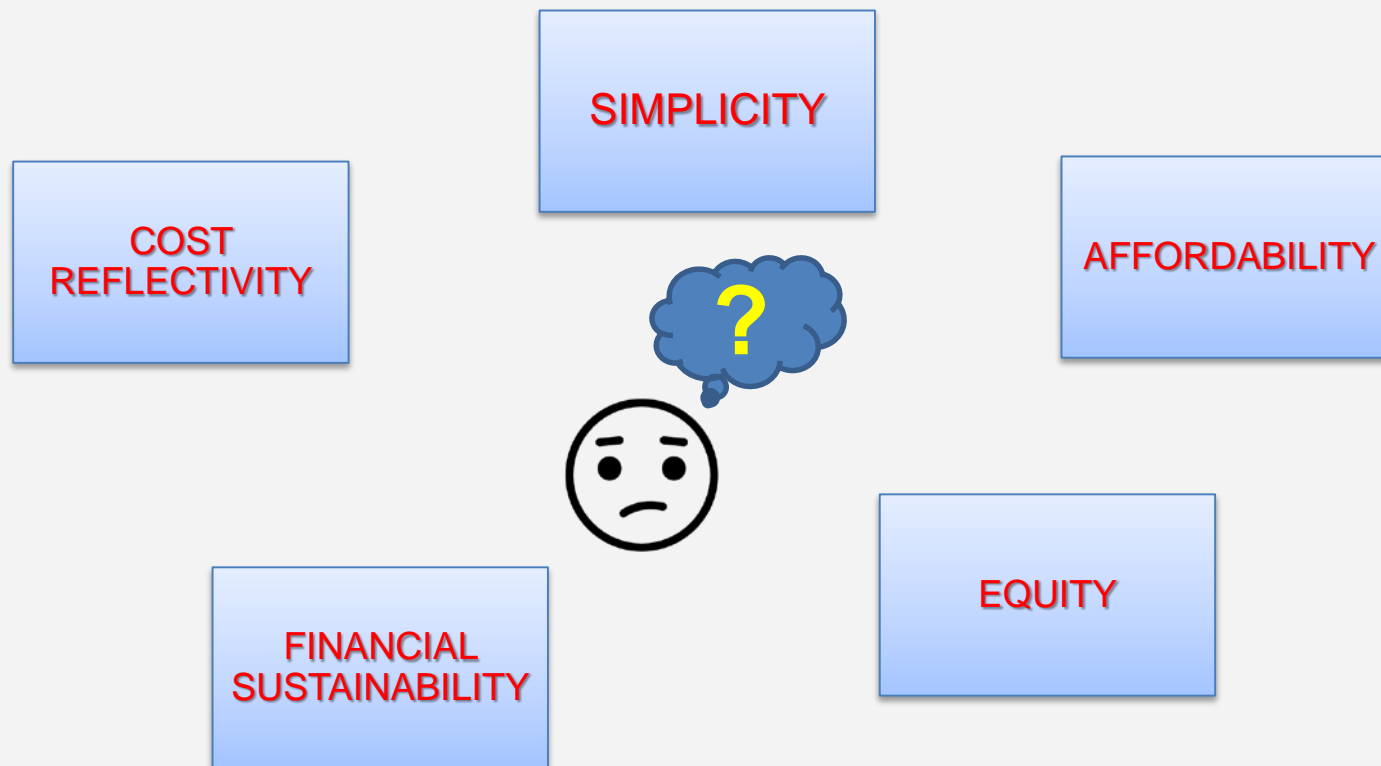
- The move towards capacity tariff which seem to be the solution to treat the «prosumer» problem, could in the medium term produce grid defections?

- Which is the power of network price signals in orientating the consumption patterns of final customers?

  Signal coming from time of use energy pricing can be in conflict with signals of local congestions coming from dynamic network tariffs and time of use network tariffs.

Thank you for your attention!