TECHNOLOGY FACTSHEET

v.2

DIABATIC COMPRESSED AIR ENERGY STORAGE (CAES) FOR LARGE-SCALE TEMPORAL ELECTRICITY STORAGE

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Sector	Electricity generation
ETS / Non-ETS	Non-ETS
Type of Technology	Storage
Description	Compressed air energy storage (CAES) is based on storing electricity as compressed air. Compressed air is typically stored underground in suitable geological formations (salt, hard rock and porous rock or aquifer). Aboveground CAES is also a possibility, however investment costs in this case are higher. This factsheet only considers underground CAES whereas air is expanded through a turbine to produce electricity. Diabatic CAES uses fuel (typically natural gas) to heat the expanding air (JRC ETRI, 2014). CAES is typically a large-scale, long-term storage option, and it is applied on the centralised grid. As of 2017, there are two large diabatic CAES projects installed globally, the first one is a 290 MW plant in Germany, and the second one is a 110 MW plant in Alabama, the US (DNV KEMA, 2013; IRENA, 2017).
TRL level 2020	TRL 9
	The two large existing projects were already installed in 1978 (Germany) and in 1991 (Alabama) (DNV KEMA, 2013). More plants are being prepared, such as a plant in Larne, Ireland (TNO, 2018).

TECHNICAL DIMENSIONS

Capacity	Functional Unit		Value and Range								
	kWh		3,000,000								
			580,000			-			3,000,000		
Potential	NL	GWh	Current			2030			2050		
			550			-			-		
			Min	–	Max	Min	–	Max	Min	–	Max
Market share	Global utility scale electricity storage	%	0.30%			-			-		
			Min	–	Max	Min	–	Max	Min	–	Max
Capacity utlization factor	1.00										
Full-load running hours per year											
Unit of Activity	PJ/year										
Technical lifetime (years)	30 years (IEA ETSAP & IRENA, 2012), 40-55 years (JRC ETRI, 2014). Up to 200,000 cycles (DNV KEMA, 2013)										
Progress ratio	N/A (JRC ETRI, 2014)										
Hourly profile	No										
Explanation	Project specifications determine capacity and detailed project design. An example from TNO (2018): 100 MW/2,860 MWh (26h discharge time) with a cavern of 538.000 m3. Assuming charge time is similar to discharge time (26h), then the compressor capacity required will be 350 m3/s. If faster charge times are desired, a larger compressor is required. The potential estimated by TNO is 50% of the theoretical storage potential in onshore salt caverns in the Netherlands. These salt caverns can also be used for natural gas or hydrogen storage and may therefore not be completely available for CAES (TNO, 2018). As of 2015, the global grid-connected CAES capacity is 440 MW (0.3%) and it is the largest installed utility scale storage after pumped hydro. Pumped hydro dominates the large-scale electricity storage market with over 140 GW installed capacity (99.1% of installed capacity) (IRENA, 2015). More projects are under development (TNO, 2018). Reports on lifetime vary from 30 years (IEA-ETSAP & IRENA, 2012), to 40-55 years (JRC ETRI, 2014), and to 20-100 years (IRENA, 2017).										

COSTS

Year of Euro	2015								
Investment costs	Euro per Functional Unit	Current			2030			2050	
	€ / kWh	35			31			26	
		2	–	50	31	–	40	26	–	26
Other costs per year	€ / kWh	-			-			-	
		Min	–	Max	Min	–	Max	Min	–	Max
Fixed operational costs per year (excl. fuel costs)	€ / kWh	0.46			0.40			0.34	
		0.46	–	1.01	0.40	–	0.80	0.34	–	0.34
Variable costs per year	€ / MWh	1.21			1.21			1.21	
		1.21	–	30.00	1.21	–	30.00	1.21	–	1.21
Costs explanation	There are significant degrees of freedom in designing (diabetic) CAES system, such as pump size and turbine size which determine in combination with the reservoir size the charge and discharge times and the energy/power ratio. Design choices such as these influence system costs, which means there are relatively large ranges in costs possible. The sources used have been chosen because they are recent publications and include projections up to (at least) 2030. JRC ETRI (2014) is used as primary source because it has the most complete set of data, including CAPEX and FOM/VOM estimates up to 2050. Details of the cost estimates are not, or only shortly, elaborated in these reports, and estimations of investment costs from other sources vary from 2 €/kWh to 500 €/kWh. Data points for the current year (2020) differ per source: 2020 for JRC ETRI (2014), 2016 for IRENA (2017), 2013 for JCH JU McKinsey (2015), and 2009 for Chen et al. (2009). The main FOM costs calculated using the JRC ETRI (2014) assumption that they represent 1.3% of investment costs. It is assumed that FOM costs remain 1.3% of investment costs in 2020, 2030 and 2050. Other FOM costs are from FCH JU Mckinsey (2015) that states FOM costs as 15 €/kW/year in 2013 and 12 €/kW/year in 2030. These have been calculated to M€/GWh/year assuming a standard storage capacity of 15 hours (200MW/3000MWh system - JRC ETRI, 2014). VOM costs are only provided for 2013 by JRC ETRI (2014) and it is assumed the they remain the same in 2020, 2030 and 2050. VOM costs are defined by JRC ETRI (2014) as production-related O&M costs that vary with electrical generation. They exclude personnel, fuel, and CO2 costs.								

ENERGY IN- AND OUTPUTS

Energy carriers (per unit of main output)	Energy carrier	Unit	Current			2030			2050	
	Main output: Electricity	PJ	-1.00			-			-	
			-1.00	–	-1.00	Min	–	Max	Min	–	Max
	Electricity	PJ	0.77			-			-	
			0.77	–	0.77	Min	–	Max	Min	–	Max
	Natural gas	PJ	1.13			-			-	
			1.13	–	1.13	Min	–	Max	Min	–	Max
		PJ	-			-			-	
			Min	–	Max	Min	–	Max	Min	–	Max
Energy in- and Outputs explanation	The required amounts of electricity and natural gas are stated to obtain 1 PJ of electrical output - based on Huang et al (2017). Note that the output of electricity is higher than the input due to the addition of heat from the combustion of natural gas. Total efficiency is 53% in this configuration, which is at the high end of the 42-54% range reported by DNV KEMA (2013).									

EMISSIONS (Non-fuel/energy-related emissions or emissions reductions (e.g. CCS)

Emissions	Substance	Unit	Current			2030			2050	
			-			-			-	
			Min	–	Max	Min	–	Max	Min	–	Max
			-			-			-	
			Min	–	Max	Min	–	Max	Min	–	Max
			-			-			-	
			Min	–	Max	Min	–	Max	Min	–	Max
			-			-			-	
			Min	–	Max	Min	–	Max	Min	–	Max
Emissions explanation										

OTHER										
Parameter	**Unit**	**Current**			**2030**			**2050**		
Depth of discharge	%	N/A			-			-		
		-	–	-	*Min*	–	*Max*	*Min*	–	*Max*
Charge time	Hours	26			-			-		
		26	–	26	*Min*	–	*Max*	*Min*	–	*Max*
Discharge time	Hours	15			-			-		
		2	–	26	*Min*	–	*Max*	*Min*	–	*Max*
Self discharge	% / month	-			-			-		
		-	–	-	*Min*	–	*Max*	*Min*	–	*Max*
Explanation	Charge and discharge times are project dependent (see explanation in technical dimensions section). JRC ETRI (2014) states that the minimum time necessary to charge a unit is approximately 8 minutes. TNO (2018) gives the example of 26 hours charge time as stated above. The main discharge time is based on the size of typical system as reported by JRC ETRI (2014) - 200MW/3,000MWh. TNO (2018) compares three plants (Huntdorf (DE), McIntosh (US), and Larne (IE)) with varying specifications (Huntdorf capacity is ca. 300 MW and 600 MWh and McIntosh capacity is ca. 110 MW and 2,860 MWh). Capacity, charge time, and discharge time depend, amongst other things, on cavern size and the specifications of the turbine and compressor used for the project.									

REFERENCES AND SOURCES

JRC 2014. Energy Technology Reference Indicators (ETRI) projections for 2010-2050

DNV-KEMA 2013. Systems Analysis Power to Gas (deliverable 1: Technology review)

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Luo et al. (2015). Overview of current development in electrical energy storage technologies and the application potential in power system operation

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FCH JU McKinsey (2015). Commercialisation of energy storage in Europe

Chen et al (2009). Progress in electrical energy storage system: A critical review

Huang et al (2017). Techno-economic modelling of large scale compressed air energy storage systems