Document number

Future European Heat

Renewable heating comparisons

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DNV KEMA Energy & Sustainability

DNV KEMA serves the entire energy industry

Exploration & Production	Transport & Distribution	Use	Policy, Strategy & Trade




- Providing guidance, direction, evidence and support to manage opportunities and risk in changing and complex energy markets
- To help our clients successfully anticipate market developments and make strategic business decisions
- We combine in-depth knowledge of international markets, technologies, and best practices with analytical skills to advise across the entire energy value chain

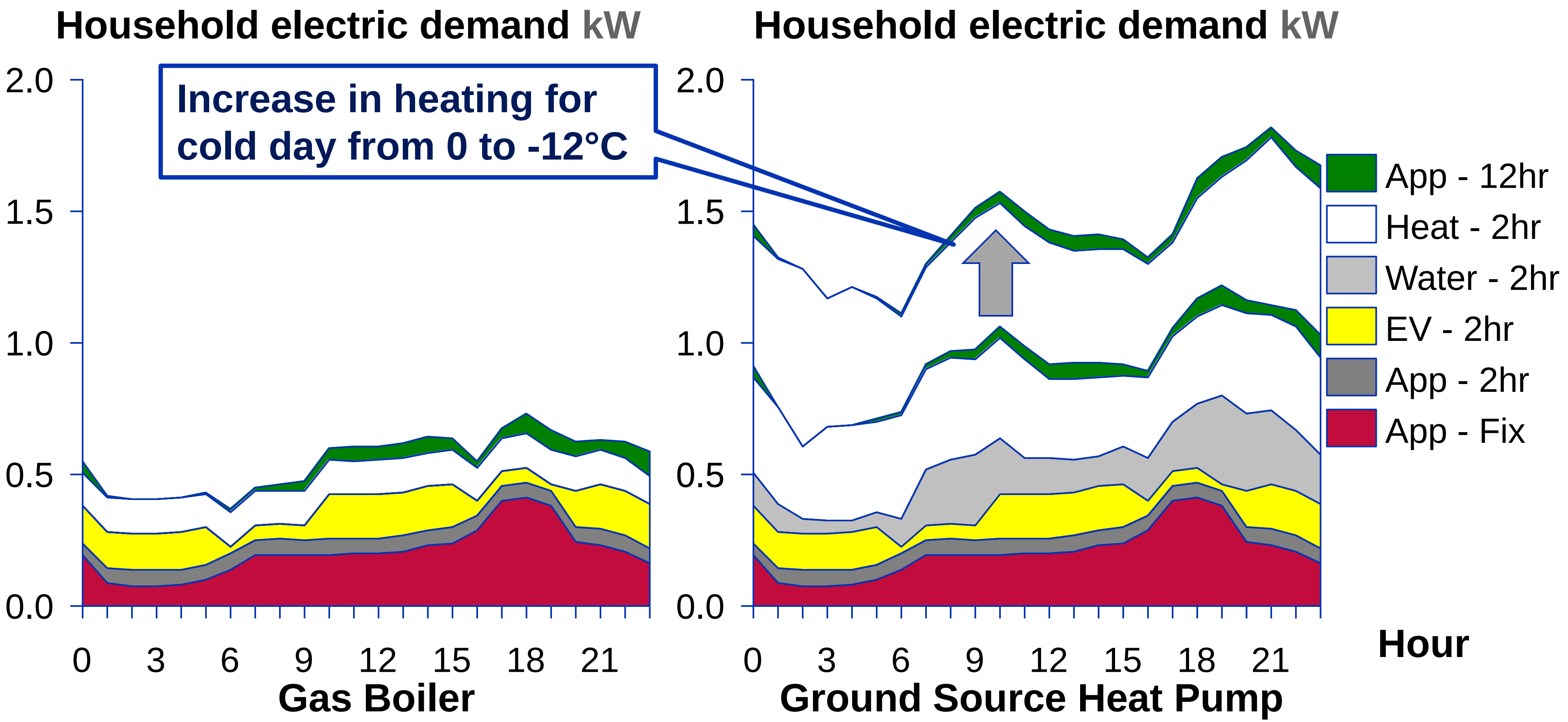
DNV KEMA – Future Energy Systems

- Pathway analysis to achieve business and environmental goals
  - End user demand
    - Electricity, Heating, Hot Water, Cooling
  - Conversion technologies
    - Boiler, Heat Pumps, PV, Wind, Central Fossil plants, etc.
  - Supply and delivery of primary energy
    - Production, Transmission, Distribution

- Energy policy development and evaluation
- Technology (development) assessments
- Energy market design and network access
- Market rules and technical codes
- Investment Decision Support & Benchmarking

Rowhouse electric demand – gas boiler to GHP

- On cold winter day (-12°C), shift from gas boiler to GHP increases peak load 200%
- On moderate winter day (0°C), shift from gas boiler to GHP doubles peak load

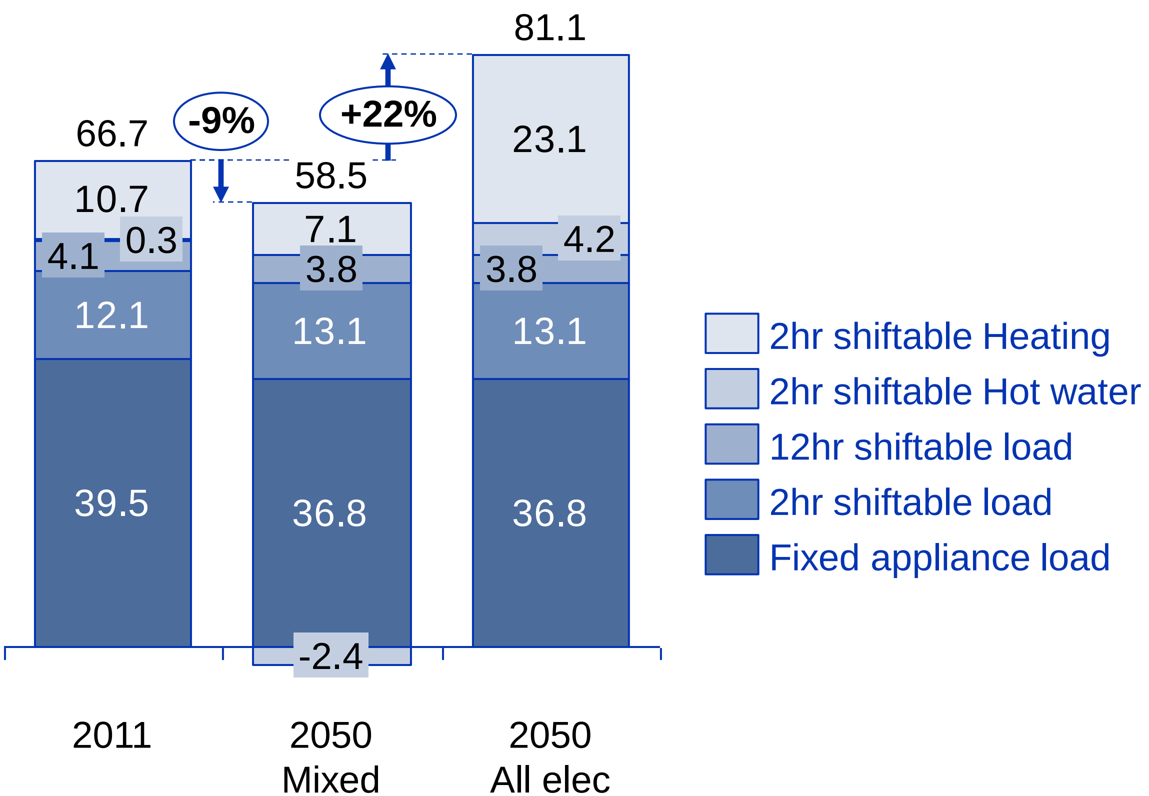


Source: TREIN, SEPATH, DNV KEMA analysis

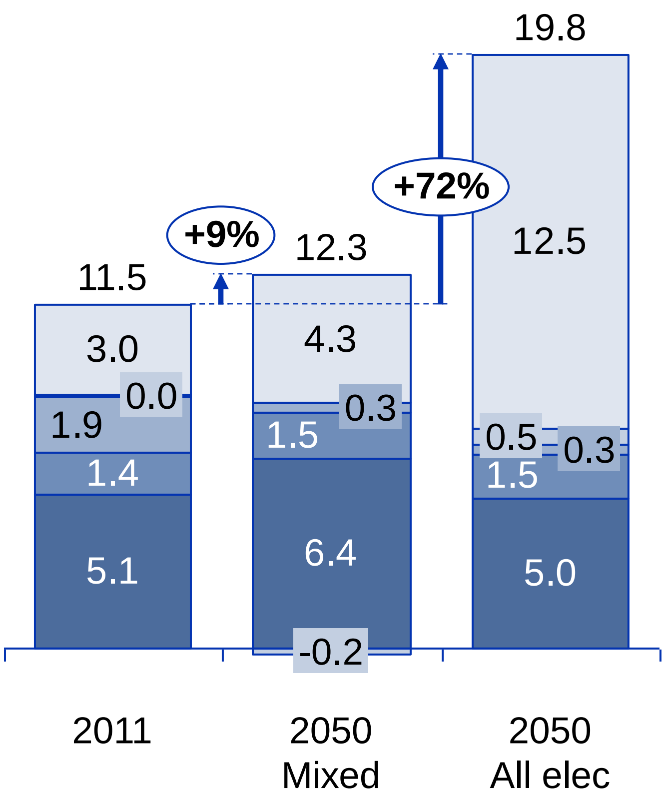
NL built environment demand under two scenarios

- Electric scenario increases demand 33% over mixed scenario in 2050 (+20 TWh/yr)
- Peak load in all electric scenario is 61% higher than mixed scenario (+7.5 GW_e)

Electricity demand TWh_e/yr



Peak load[1] GW_e



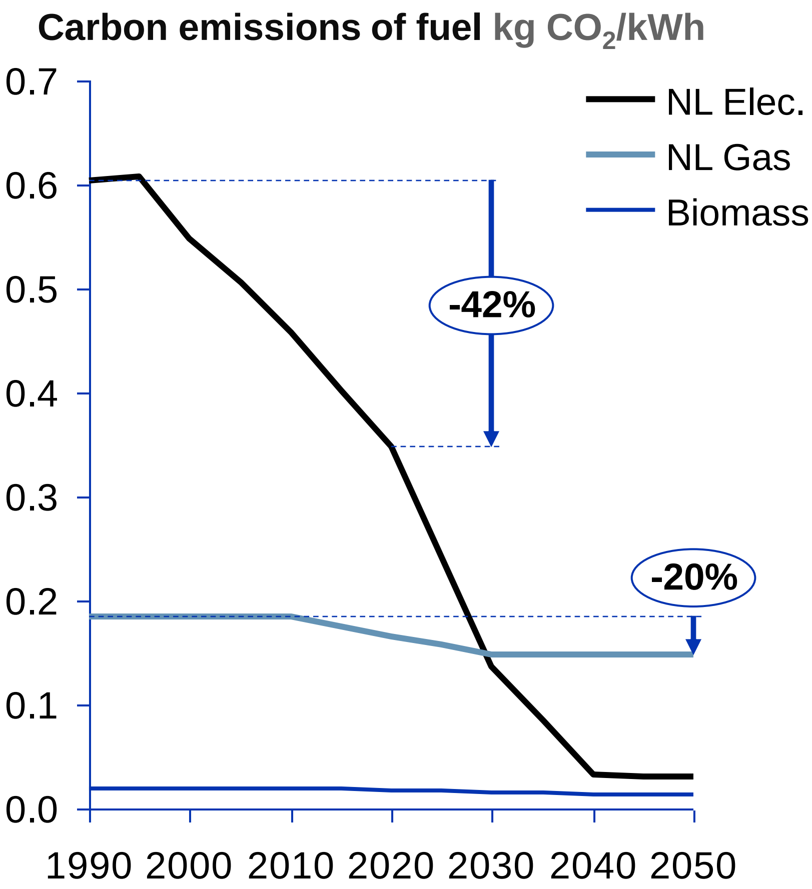
1 Fixed load varies on peak 2050 day because the overall peak occurs on different days/times in each scenario
Source: DNV KEMA analysis

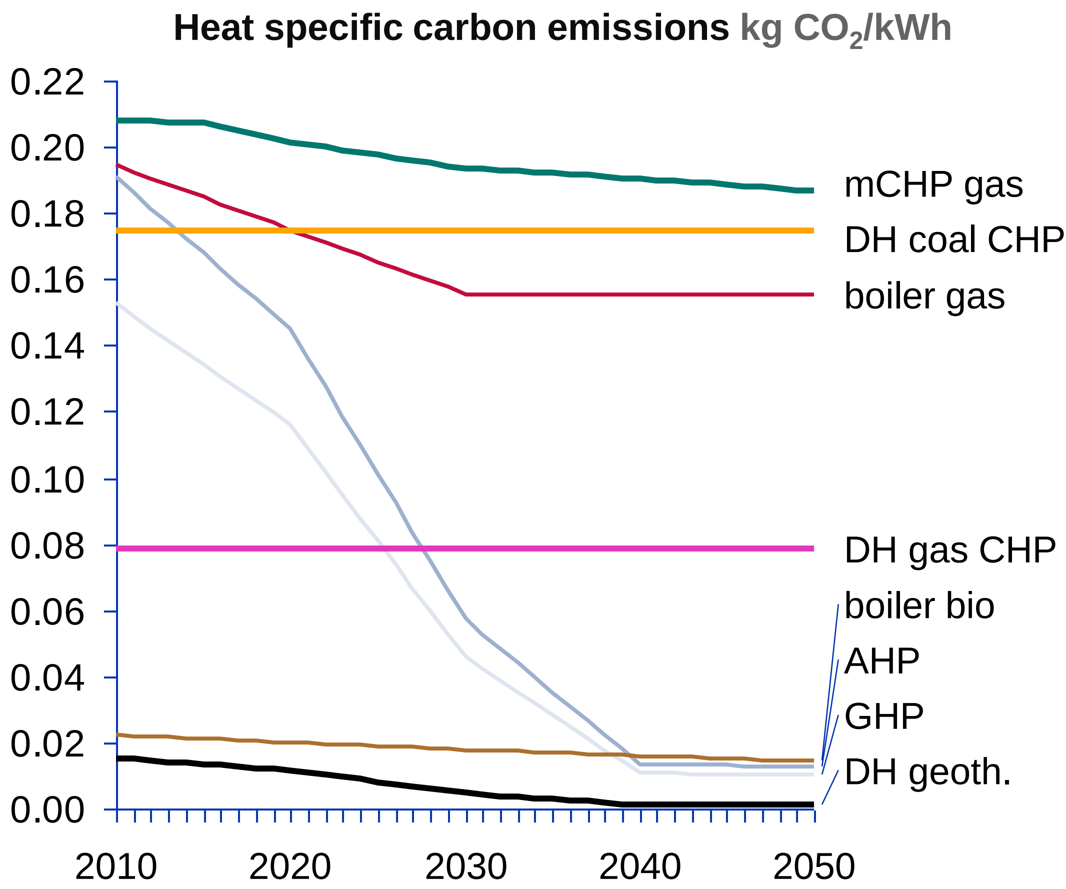
Four business models to develop projects

1. **Economic** driven projects benefit from acceptable returns without direct subsidy (though often there is still some subsidy)
   - Fuel switching to biomass from fuel oil (benefit from avoided taxes)
2. **Subsidized** require a reduction in financed capital costs and/or a feed in tariff to ensure future revenues byond market prices
   - Solar thermal district heating, biogas, and biomethane
3. **Regulated** building efficiency standards can force new technologies
   - Ground source heat pumps, insulation, glazed windows, etc.
4. **microFinance** allows individuals to aggregate and place their capital into projects that may not offer the returns required by the private sector, but:
   - 50% of consumers are willing to pay a <5% premium for RES
   - 10% of consumers are willing to pay a 5-10% premium for RES
   - Only 1% of consumers are willing to pay a >10% premium for RES

NL CO_2 intensity per heat delivered by technology

- Specific carbon emissions (kg CO_2/kWh) are assumed to decrease greatly by 2050 due to decarbonization of electricity mix and development of low carbon gases





Source: EU PRIMES, ECF Power Perspectives 2030

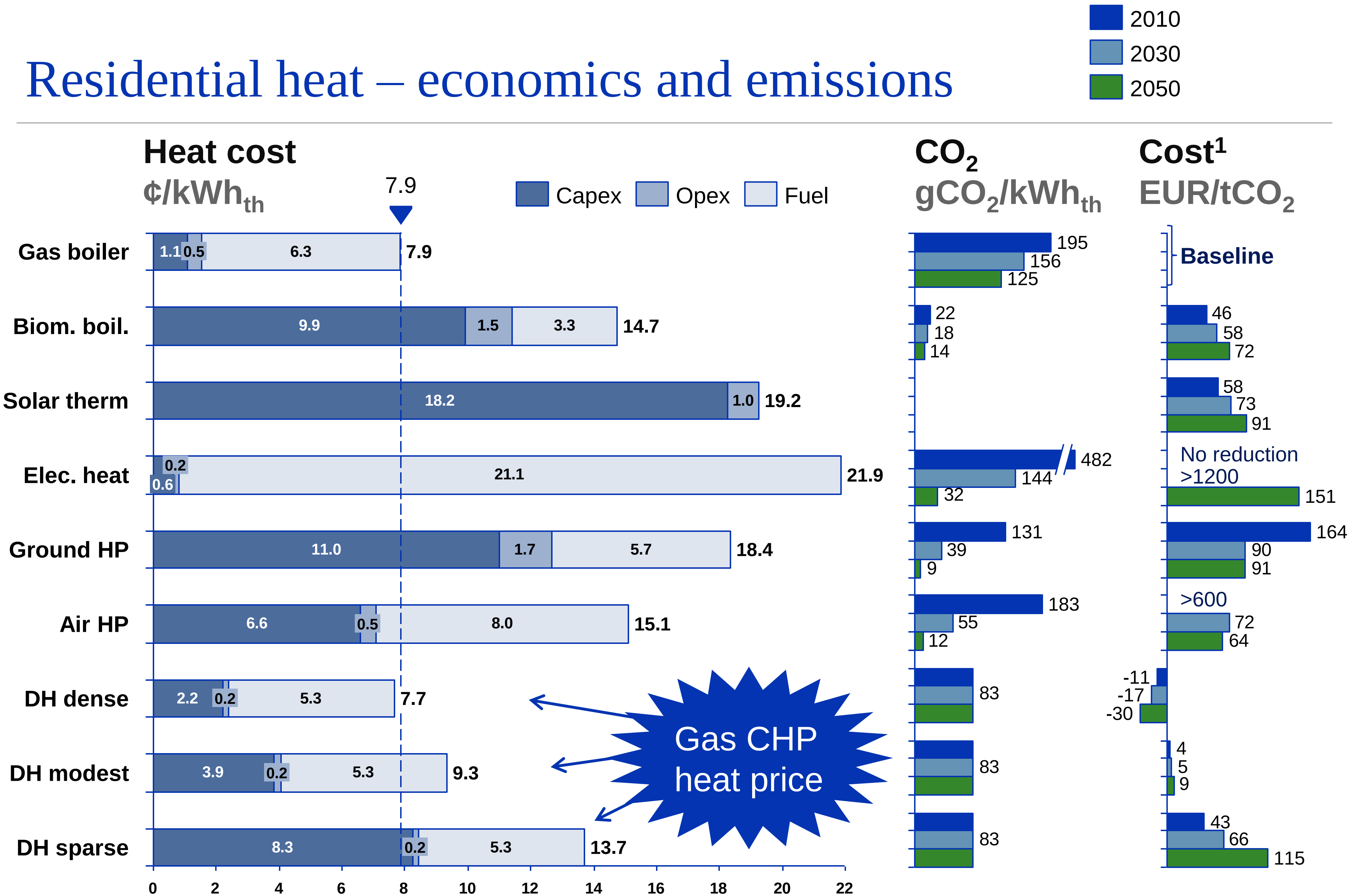
Explanation of heat economic analysis assumptions

- Heat economic evaluation occurs in two stages:
  1. HOME Comparison (multi-kW_{th}), also with assumed DH networks[1]
  2. DH Comparison (capacity of 10 MW_{th})
- Constant lifetime of 20 years and WACC[2] of 6% assumed across all options
  - Fuel prices are different for each scale and carbon intensity decreases to 2050 as follows:

Fuel	HOME price [¢/kWh]	DH price [¢/kWh]	Carbon intensity [kg CO_2/kWh]		
			2010	2030	2050
Electricity	20	10	0.458	0.137	0.030
Gas	6	4	0.185	0.148	0.118
Biomass	4	3	0.02	0.016	0.013
CHP heat	4	4	0.175	0.079	0.001

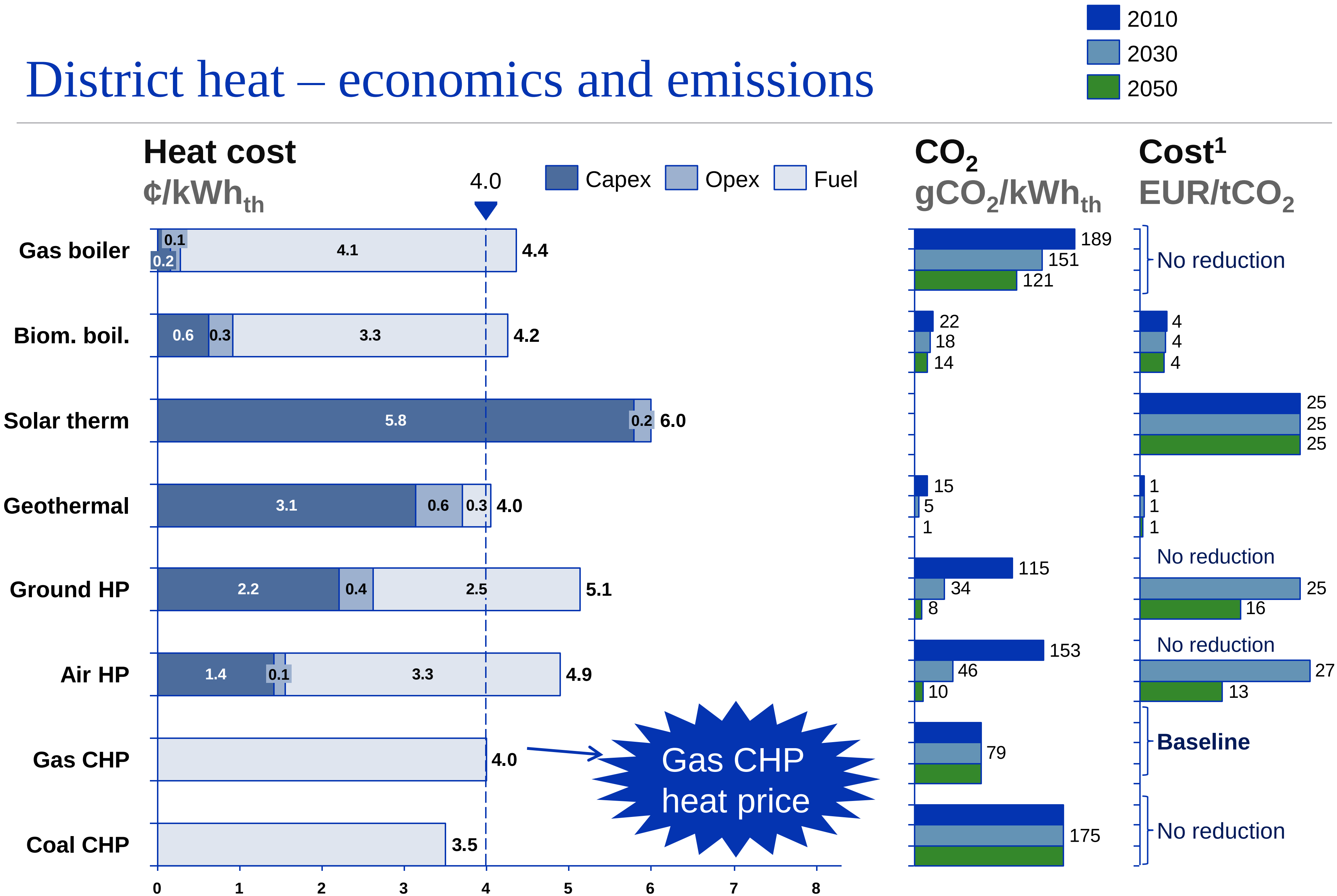
1 DH heat supply price assumed 40 €/MWh_{th}; 2 Weighted Average Cost of Capital;
Source: DNV KEMA analysis

Residential heat – economics and emissions



1 Carbon mitigation cost calculated by comparison to gas boiler for middle case of each technology with given year's fuel carbon intensity
Source: DNV KEMA analysis

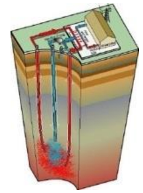
District heat – economics and emissions



1 Carbon mitigation cost calculated by comparison to gas boiler for middle case of each technology with given year's fuel carbon intensity

Source: DNV KEMA analysis

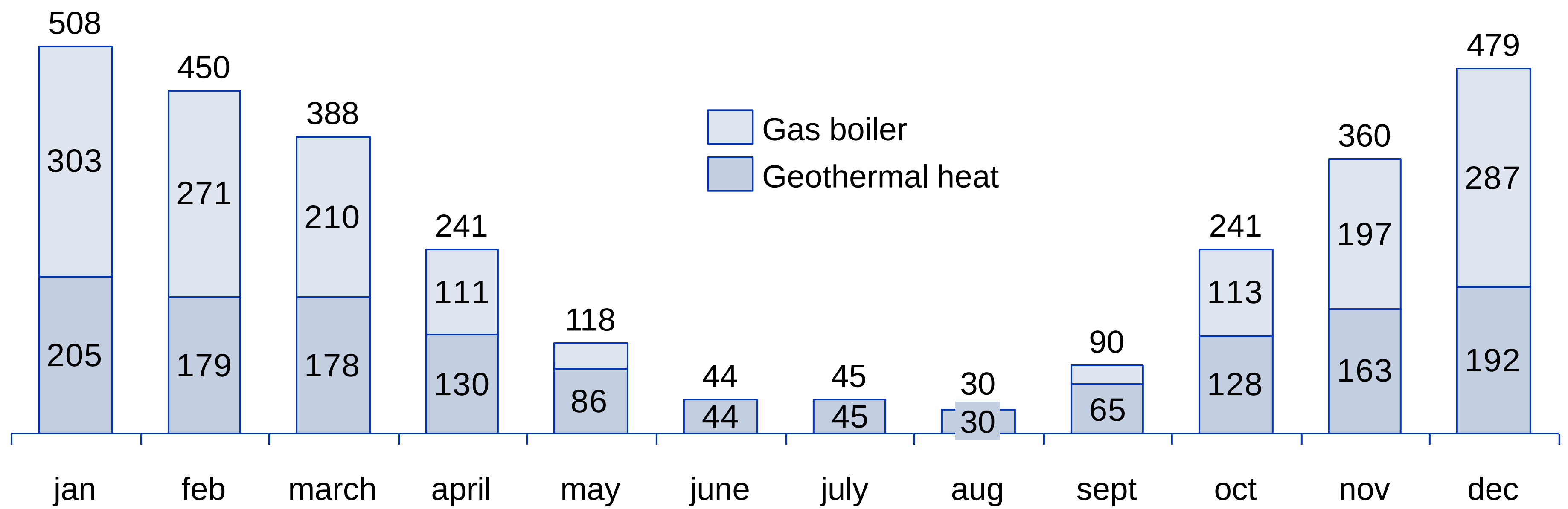
Geothermal CHP DH example – Germany



- **Landau**
  - 48% of heat load is met with geothermal which operates at ~67% capacity factor (utilization)[1]
  - ~20 million EUR total investment
  - Geothermal water resource at 3,200 m depth and 155°C (50-70 l/s flow rate)
  - ORC-process[2] for CHP (with back cooling for electricity generation outside heating season)

Commisioned	2007
CHP process	ORC[2]
Aquifer temp	155
Drill depth	3,200m
MW_{th}	5.1
MW_e	3

Landau heat delivery to specific city area MWh_{th}

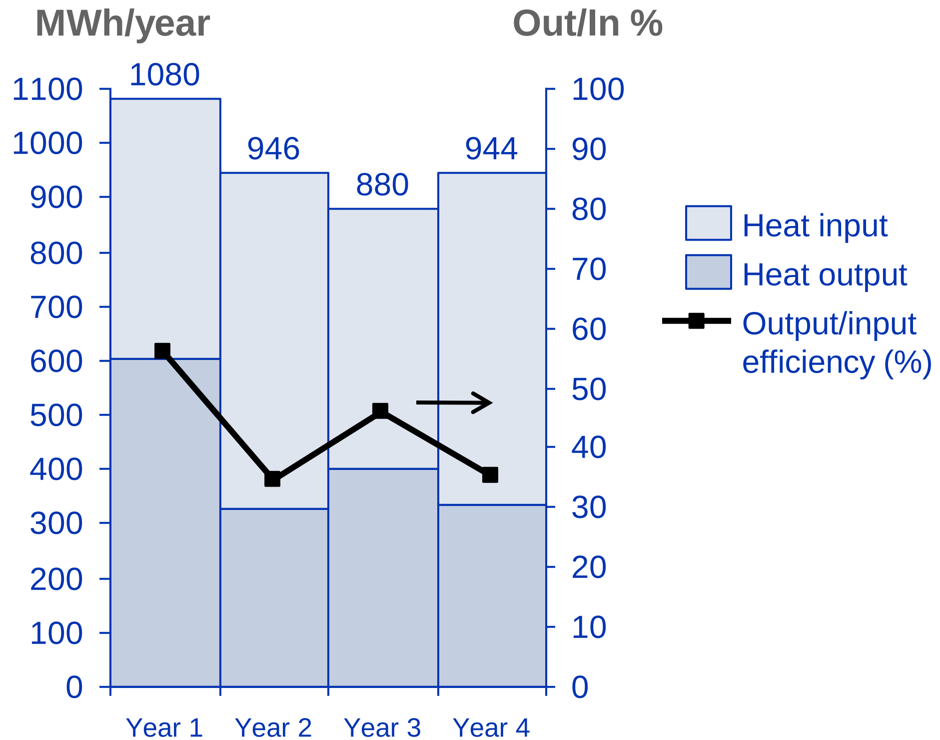


1 Utilization accounts for lower heat capacity in summer due to CHP constraints (would be 58% using max winter heating capacity);
2 Organic Rankine Cycle;
Source: Menzel: Geothermische Stromerzeugung in Landau 2007, Knapek: Geothermieprojekt Unterhaching 2007

Seasonal thermal storage – performance

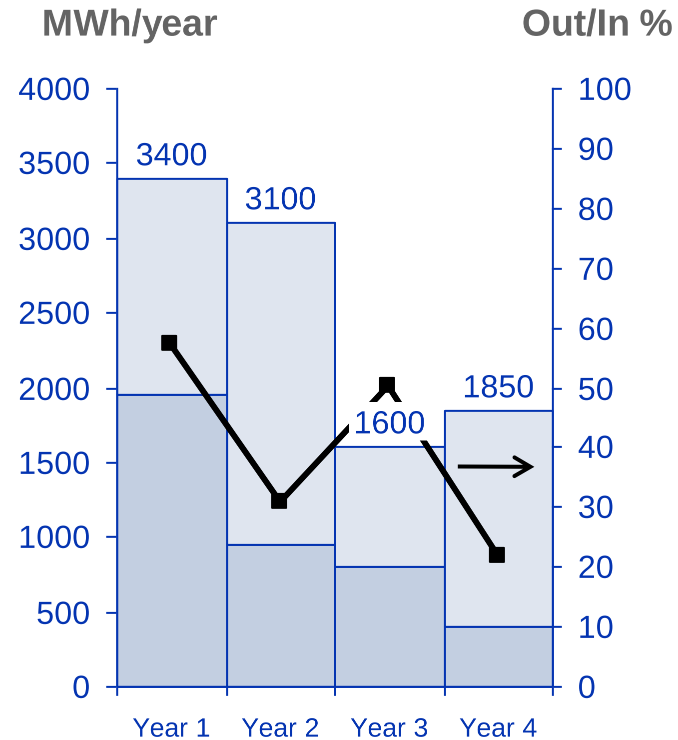
- Performance of seasonal storage depends on storage technology and capacity of storage unit
- A large challenge is the reduced discharge temperature which has to be compensated by heat pumps or peak boilers, and is proportional to the storage loss

Water-tank energy storage balance[1]



12,000 m³ Hot water storage tank

Aquifer energy storage balance[2]



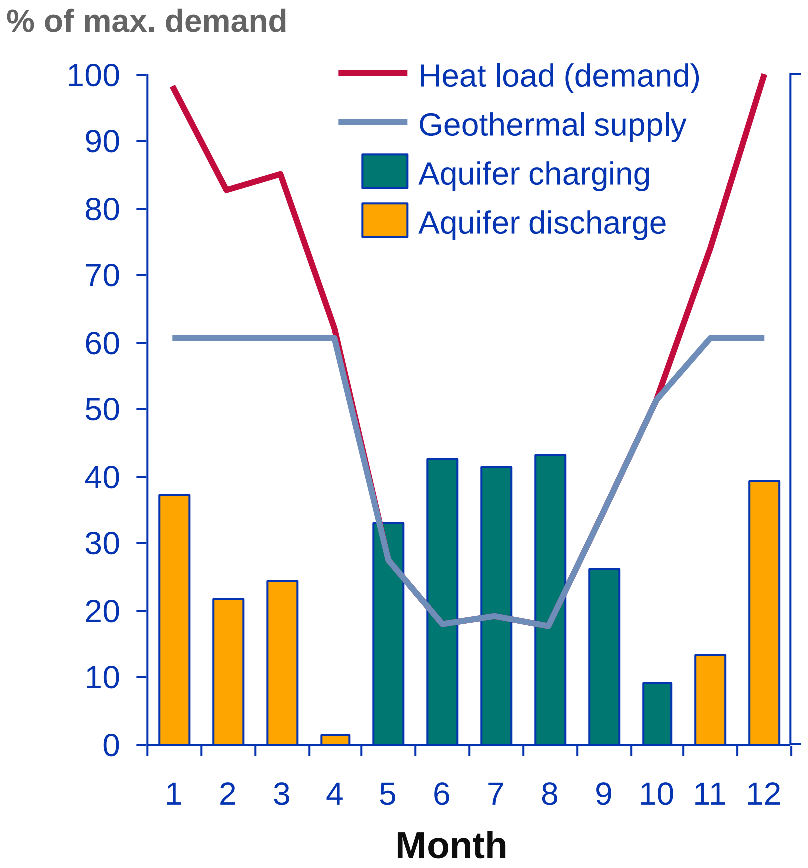
Aquifer thermal energy storage

1 Example Friedrichshafen, 12,000 m³ concrete tank, installed 1997; 2 Example Reichstag-Building Berlin, installed 2002
Source: BINE Informationsdienst 2001

Combining geothermal and aquifer seasonal storage

- Requirements for the combination:
  - Appropriate geologic conditions for deep geothermal energy extraction and seasonal heat storage in an aquifer at the same place
  - Dimensioning of the deep geothermal system (flow rates) for approx. 60% of max. monthly heat load
  - Dimensioning of the aquifer storage system (flow rates) for approx. 70% of deep geothermal system
- Benefits:
  - Supply system with very high fraction (up to 100%) of renewable energy
  - High number of yearly utilization hours for both geothermal part systems
  - Utilization of deep geothermal resource up to 90%
- Challenge:
  - Heat for charging the aquifer is not free
  - Cost optimum must be found concerning dimension of deep geothermal probes, aquifer probes and peak load boiler

Load simulation of deep geothermal with aquifer storage for 100% heat supply



1 Assumption of 70% storage efficiency
Source: DNV KEMA internal calculations

Solar DH – Brædstrup, Denmark (1/2)

Specifications[1]

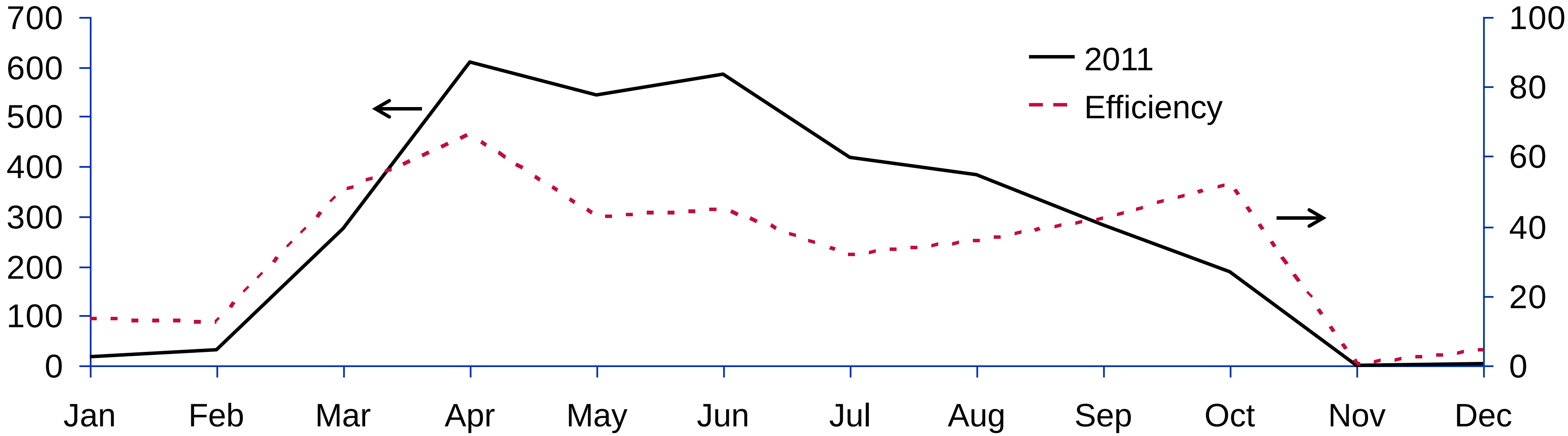
- Flat plates (8,012 m^2) placed on ground
  - Operational since 2007 in combination with gas CHP/boilers and 2,000 m^3 steel water tank
- Heat output:
  - 2011: 3.3 GWh/yr (380 $kWh_{th}/m^2/yr$)
  - 2010: 3.0 GWh/yr (340 $kWh_{th}/m^2/yr$)
  - ~39% efficient from 924 $kWh_{solar}/m^2/yr$
- Delivers 7% of annual 42 GWh heat load

Economics

- Total investment of 1,640 k€
  - 205 €/m^2 solar collector area
  - Subsidies of 320 k€ (20% of capex)
  - Heating network already in place
- Operating cost of 0.66 €/MWh solar heat (~2 k€/yr)
- Cost of solar heat:[2]
  - Without subsidy: 55 €/MWh (25)
  - With subsidy: 45 €/MWh (21)

Monthly heat production MWh

Solar-to-heat efficency %

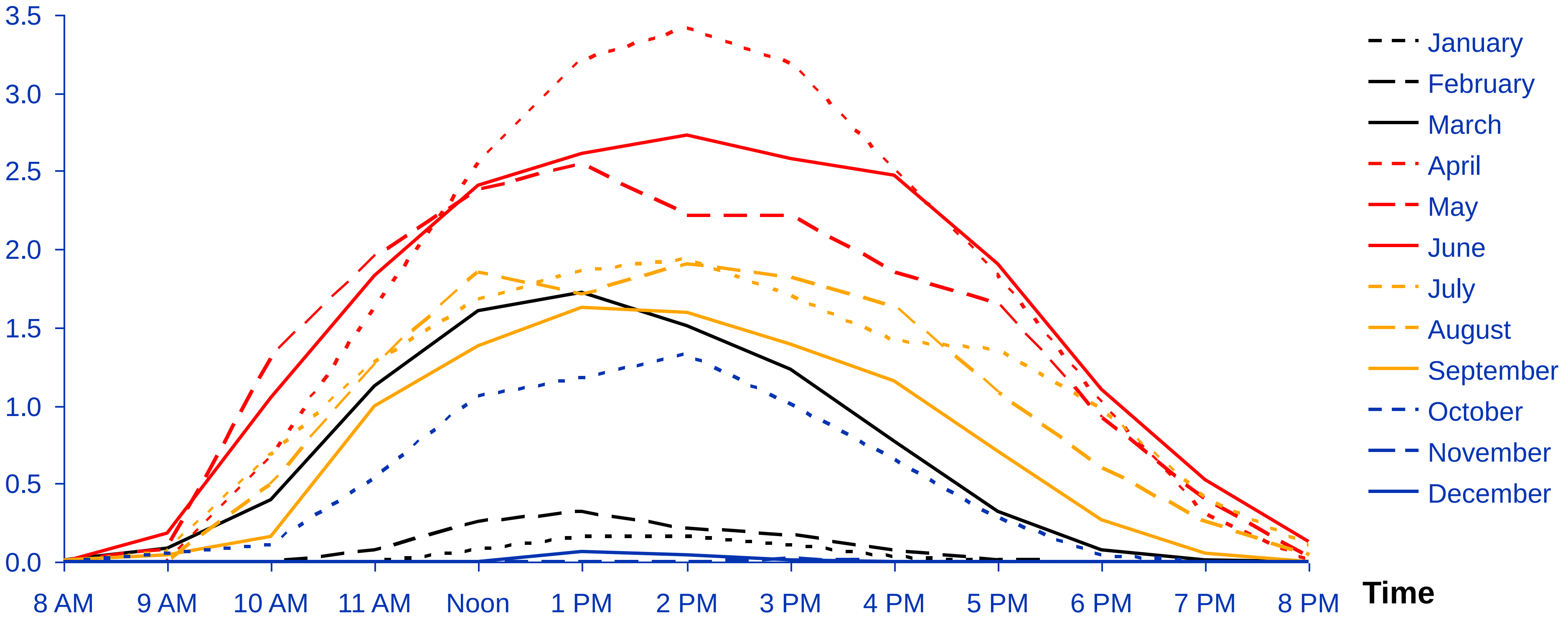


1 Brædstrup DH plant has recently been expanded with 10,000m^2 solar panels, 5,500m^3 tank and 19,000 m^3 of borehole storage, 10 MW E-boiler and heat pump 2 Assumed WACC of 6% and 20 yr lifetime, values in (parenthesis) corresponds to 0% WACC
Source: Solvarmedata.dk 2011, SDH April 2009

Solar DH – Brædstrup, Denmark (2/2)

- Heat demand at night does not align with heat production during the day, and heat production is nearly negligible from Nov thru Feb when only 2% of heat is produced (13% comes in March and October)
- Thermal storage is required for DH networks with high solar contributions, but in this example solar only provides 7% of the annual demand[1], though this corresponds with ~26-43% of the summer heat demand[2]

Average hourly heat production per month in 2011[3] MWh



1 Remaining heat provided by gas CHP and gas boilers; 2 Assumes space heating is from 50-70% of total heat demand;
3 Data represents average hourly for each month
Source: Solvarmedata.dk 2011