Project EPIC

Work Package 6:

Network investment results for Use Case 6: High Solar Deployment in South West Bristol

Final Draft

EPIC

Energy Planning Integrated with Councils

This report was produced for	Project EPIC
Issue date	29/07/22
Version	First Draft
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1. Glossary of Terms

Abbreviation	Term
BEZ	Bath Enterprise Zone
BU	Bottom Up: Bottom Up analysis starts by modelling the load at individual distribution substations and aggregating up to HV feeder level.
CAPEX	Capital Expenditure
CBA	Cost Benefit Analysis
DFES	Distribution Future Energy Scenarios
DNO	Distribution Network Operator
DUoS	Distribution Use of System charges
ENA	Energy Networks Association
ESA	Electricity Supply Area
EPIC	Energy Planning Integrated with Councils
EV	Electric Vehicle

Abbreviation	Term
HV	High Voltage
HV NAT	High Voltage Network Analysis Tool
INM	Integrated Network Model
LCT	Low Carbon Technology
LV	Low Voltage
LV NIFT	Low Voltage Network Investment Forecasting Tool
MWh	Megawatt Hour i.e. the energy used by consuming 1MW of power for an hour.
NPC / NPV	Net Present Cost / Net Present Value
OPEX	Operational Expenditure
SPA	Strategic Planning Area
TD	Top Down: Top Down analysis uses monitored HV feeder load profiles as a starting point to add the impact of LCT uptake.
TOTEX	Total Expenditure, the sum of all cost categories on either the network or society.
WECA	West of England Combined Authority
WP	Work Package
WPD	Western Power Distribution
WS CBA	Whole System Cost Benefit Analysis
WWU	Wales and West Utilities

Clarification on the meaning of 'Whole Systems'

The project EPIC trial sought to consider the impacts of different investment strategies across the electricity and gas networks and on wider society. The term 'whole systems' has been used to reflect this intent, and appears throughout this report.

The results discussed do contain a whole systems element, with impacts on the electricity network and society being considered alongside each other. However, without gas network impacts incorporated into these results, 'whole systems' only constitutes these two stakeholders.

Further, there is the view that the term 'whole systems' should be reserved for analyses considering impacts from generation/production through transportation/storage, and on to end use. This goes far beyond the 'whole systems' results covered in this report.

The specific impacts considered in this report are detailed within section 4.1.3.

2. Document purpose and associated project deliverable

The Energy Planning Integrated with Councils (EPIC) Project trial is investigating the whole systems impact of a number of Low Carbon Technology (LCT) deployment strategies and investment approaches. Five use cases, set out in Work Package 2 (WP2) are being investigated, these are summarised in Table 1, below. Each use case passes results from High Voltage (HV) and Low Voltage (LV) network analysis tools, specified in WP4, through a Whole System Cost Benefit Analysis (WS CBA) tool. This WS CBA tool was developed outside of project EPIC by the Energy Networks Association (ENA) as part of their 'Open Networks" project, its specification and usage are detailed in WP3.

This document forms part of WP6 of the EPIC Trial. It describes the results of this whole systems cost benefits analysis for **Use Case 6**, assessing the impact on the network and society of a high deployment of ground mounted solar in the SW Bristol Strategic Planning Area (SPA), the analysis was conducted on the Nailsea Primary.

Table 1: The project EPIC Trial use cases

Use Case 1: EV charger deployment	Comparing the network impact two EV charger deployment strategies, one with a greater reliance on LV connected on-street residential chargers, the other with a greater reliance on HV connected rapid charging hubs.
Use Case 2: Energy Efficiency	Comparing the network impact of a high, low and medium standard of energy efficiency across residential and commercial customers.
Use Case 3: Hybrid Heat pumps	Exploring the impact of using the gas network and hybrid heat pumps to reduce peak electricity demand and electricity network costs.
Use Case 4: Just in Time vs. Fit for Future	Comparing a BAU network upgrade to meet immediate demand growth, or an investment in upgraded assets to meet longer term future demand growth.
Use Case 5: Flexibility	Invest in an asset upgrade or contract a flexibility solution to delay or avoid the upgrade requirement.
Use Case 6: **Solar**	**Investigating the network impact of a higher deployment of large scale ground mounted solar. This is only tested in one Strategic Planning Area (SPA) (South West Bristol)**

Use Case 7: Heat Network	Exploring the whole systems impact of using a heat network to meet all heating demand from new developments in the SPA. This is only tested in one SPA (Bath Enterprise Zone).

Not contained within this report are project learnings, which will be collated for all the use cases within the WP7 learnings report and largely focus on procedural and systemic learnings rather than conclusions drawn from individual results. More detailed discussion around individual LV and HV results, and their origins in network modelling assumptions, will be covered within the LV NIFT and HV NAT results which will be produced as part of WP5.

3. Key outcomes and conclusions

The high solar strategy demanded significant increases in HV CAPEX, this is to be expected with additional generation connecting to the network and this increased CAPEX naturally led to increased incidence and cost of roadworks. **These combined to increase HV Network costs out to 2050 by 53%, £2.5m,** despite savings in HV OPEX and Losses.

The high solar strategy also has large impacts on society; the additional cost of roadworks was offset by additional availability of spare capacity and decreased emissions. The result was **a net benefit to society of 8% (a saving of £5m),** with the societal value of emissions being far higher than roadworks in this cost benefit analysis.

On a whole systems level, the increased HV network costs were offset by the savings to society, resulting in **a whole systems saving of £2.5m for the high solar strategy, a 2% impact.**

With this in mind, Local Authorities can plan for increased ground mounted solar deployment with confidence that it will deliver societal benefit, despite seeing increased roadworks; electricity networks have an example of the scale of investment that is required in the network in order to deliver high levels of ground mounted solar generation.

3.1. Limitations of the modelling

1) The increased cost of the high solar strategy on the network is in this case assumed to fall on the electricity network. In reality, the increased cost to the network will ultimately be passed on to customers. However, this use case has demonstrated that societal savings from reduced emissions would offset this increased passthrough cost. There have recently been changes in the allocation of costs between the customer seeking a new/increased connection capacity and what is recovered by the Distribution Network Operator (DNO) from the overall customer base via Distribution Use of System (DUoS) charges. This reduces the amount paid by the customer seeking a connection as they no longer pay towards reinforcement at voltage levels higher than their connection. This is likely to reduce the connection costs for large scale ground mounted solar deployments and therefore confirming the positive societal benefit is helpful.

2) The modelling of the use case reflected random location of new generation rather than proposed sites for solar parks. While available space and relevant permissions are more significant to site location, customers looking to connect large-scale solar are likely to select sites to minimise connection costs so this modelling may have overestimated the reinforcement costs by not modelling site selection to avoid costs.

3) The nature of the Cost Benefit Analysis method also means that significant impacts in some cost categories appear insignificant when summed into a Network or Societal TOTEX impact, or further, into a whole systems Net Present Cost (NPC).The societal cost of emissions dominates the Societal TOTEX sum, this means that the demonstrated impact of increased roadworks for the High Solar strategy does not result in a significant societal TOTEX percentage impact. Similarly, when HV network costs are combined with societal costs into a whole system NPC, the demonstrated 53% increases in HV TOTEX is outweighed by an 8% saving to society.

4. Project EPIC background

The aim of the EPIC project is to develop a network planning process that considers impacts on both the electricity and gas networks and reflects the strategic ambitions of the local authority, enabling better investment outcomes. These outcomes may lower overall cost to the consumer, offer improved risk management and also enable local partners to realise their own strategic outcomes including net zero decarbonisation, economic growth, industrial strategy and wider societal benefits. A number of previous work package deliverables have documented in detail the process of the EPIC trial, the flow chart below summarises those work packages. In light of the progress of the trial process so far, the "integrated energy development plan" output has been replaced by results reports and a series of workshops with Local Authority stakeholders which will communicate findings and discuss their impact on local energy planning.

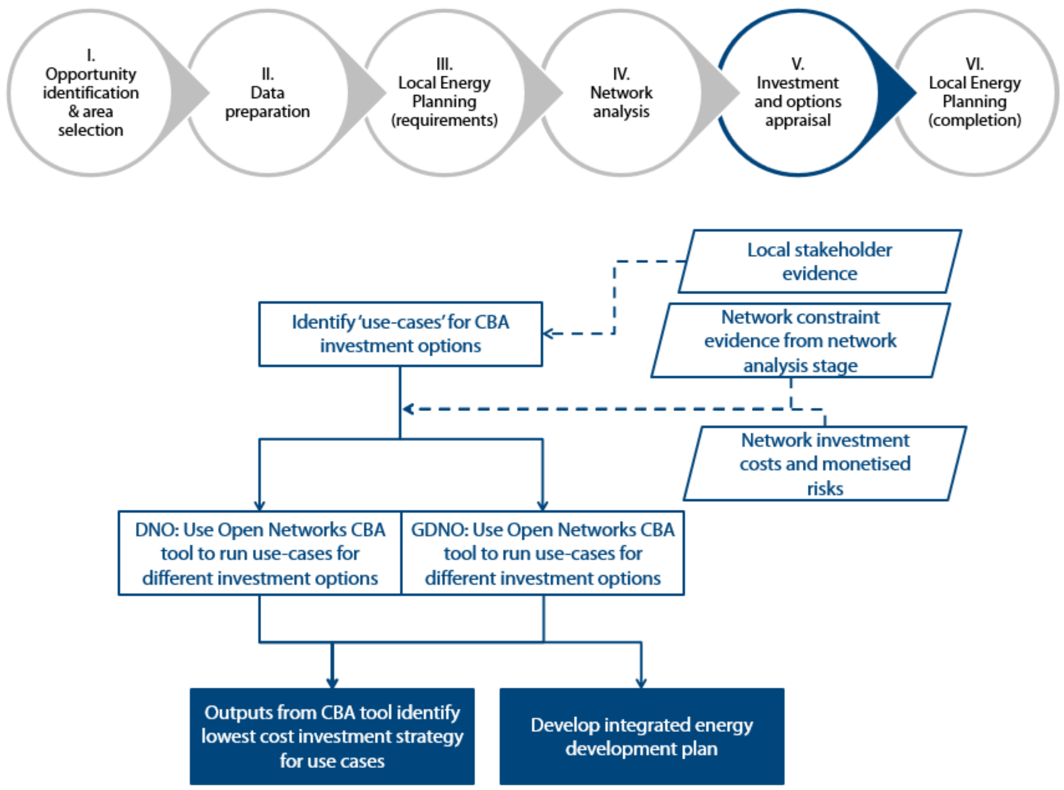

Figure 1: The EPIC Trial Planning Process.

4.1. Scope of the Whole System CBA

4.1.1. The Strategic Planning Areas (SPAs) and Primaries

The aim of the EPIC trial was to consider three SPAs selected in WP1, Bath Enterprise Zone (BEZ), the North Fringe and South Bristol. These were all served by multiple primary substations which were to be included in whole systems cost benefit analysis. At the time of the project, there was a change in the HV modelling tool used by WPD from DINIS to PSS SINCAL. This also coincided with a change in the way the network model to be used by the HV modelling tool was provided, with the creation of an Integrated Network Model (INM). This introduced a high risk that there would be issues with the network model that would take a long time to correct. To limit that risk, the decision was taken to model only a single primary within each SPA for the analysis. For the Bath Enterprise Zone, this was Dorchester St Primary. For the North Fringe, this was Cribbs Causeway Primary, and for South Bristol this was Nailsea Primary. While results for the LV network on the remaining primaries were generated, and have been used in the LV report to discuss trends across different areas, they do not feature in the whole systems CBA. Similarly, some of the initial work to create baseline profiles on the HV analysis included a wider range of primaries.

4.1.2. Gas network costs

Project EPIC faced a number of challenges in integrating gas and electricity network impacts into a whole system cost benefit analysis, these are described in more detail within the learning reports but came at a number of levels.

The initial approach taken to estimate future gas demand within each SPA was to work from 2020 WPD DFES projections. These projections take the baseline of existing gas boilers (~85% of households nationally) and add additional gas boilers from new developments between now and 2025 (based on new build EPC records). The conversion of existing gas boilers to heat pumps, heat networks, hydrogen boilers and other non-gas heating is based on assumed uptake rates of the different low carbon heating technologies. For instance, heat pump uptake is based on:

- **On-gas vs off-gas**, with much more near-term uptake in off-gas homes.
- **Floorspace**, with larger homes seeing greater heat pump uptake in the near term due to more space and higher heat demand.
- **Detached/semi-detached and owner-occupied homes** in the near term, mirroring analysis of existing RHI heat pump installations.
- **Insulation**, with homes with an EPC of C or above seeing greater uptake of non-hybrid heat pumps in the near term, and homes with an EPC of D or below seeing greater uptake of hybrid heat pumps.
- **Local authority feedback** that indicated a low carbon heat strategy gave higher weighting to heat pump uptake in the near term. For those with a specific heat network strategy, deployment of standalone heat pumps was weighted away from these areas in the near term.

The remaining on-gas homes were considered to switch from natural gas to hydrogen over the coming decades, and any remaining off-gas homes not accounted for by heat pumps, direct electric heating or night storage heaters would be assumed to be using a biofuel like bioLPG or biomass.

This 'postcode level' approach had the potential to work as a way of assigning electricity and gas network costs to the SPAs, offering a suitable granularity in gas/electricity demand changes.

However, it was found that the postcode data on the electricity and gas network did not match; there was no way of confidently unifying the two networks by postcode. This meant an approach had to be taken which used gas low pressure networks. These networks are far larger than an equivalent Electricity Supply Area (ESA), more akin to the size of a region (Bristol and Bath), they dwarfed the SPAs and did not provide sufficient granularity on demand changes of the gas network. Furthermore, the likely approaches to decarbonising the gas grid (eg. hydrogen and biomethane) are relatively large-scale, centralised approaches, which are less suited to the geographical granularity used. For instance the development of a biomethane production plant in the Bath SPA is not feasible, but it's possible that plant remote from the SPA could provide a supply of low-carbon gas.

The scenarios that were investigated resulted in small overall demand reductions on the gas network with increases from new developments being counteracted in the same area by reductions reflecting the move from gas boilers to electric heat pumps. This resulted in a lack of reinforcement requirements but at the same time the reductions did not suggest decommissioning of assets would be a useful cost saving option either. While work has been completed in developing separate scenarios to test the process of modelling gas network upgrades, reflecting the work required to support hydrogen networks, this has also proved challenging. The gas network analysis tool does not export cost outputs, instead, the costing of solutions is a distinct activity carried out on a specific basis per project; further work on costing these solutions would have to take place before any inclusion in a whole system CBA. However, analysis and cost outputs were generated through a manual approach, so gas network impacts can be covered by the EPIC process in future.

4.1.3. Cost Categories and CBA Process

The HV analysis was carried out by the HV Network Assessment Tool (HV NAT) developed by PSC and the LV analysis was provided by EA Technology using the Network Investment Forecasting Tool (NIFT). Work earlier in the project to determine which whole system costs could be considered by the network analysis tools arrived at the list of direct network and indirect societal impacts given below. Where necessary, these impacts have been monetised using calculations presented in the WP3 deliverable.

- **CAPEX:** Expenditure on asset intervention on the LV and HV networks.
- **LV OPEX:** Expenditure on LV network operation.
- **HV flexibility requirement (OPEX):** The total volume of flexibility needing to be procured on the HV network, valued at £300/MWh, as a measure of HV operating costs.
- **Losses:** Electrical losses on the HV and LV network, valued at £62/MWh.
- **Roadworks:** Number of instances of asset intervention which require roadworks. This is considered both as a direct cost for the Distribution Network Operator (DNO) at £244/instance, and indirectly on society at £1332/instance.
- **Final Demand (emissions):** The final demand met by the HV network and its associated emissions impact on society. This is valued using assumed grid carbon factors, and a societal value of carbon.
- **Spare Capacity:** The value to society of extra network capacity unlocked by network CAPEX intervention, resulting in cheaper connections. The valuation is based on an average cost per MW of LV and HV network: £199k/MW for the LV network, £298k/MW for the HV network.

Important to the estimation of the Net Present Cost (NPC) of each strategy was the provision of these costs on an annual basis out to 2050. This was possible on the LV network from LV NIFT. On the HV side, HV NAT output annual increments up to 2035, followed by five-yearly increments out to 2050.

Within the CBA tool, these costs are allocated to either the networks or to society. The diagram below outlines this allocation:

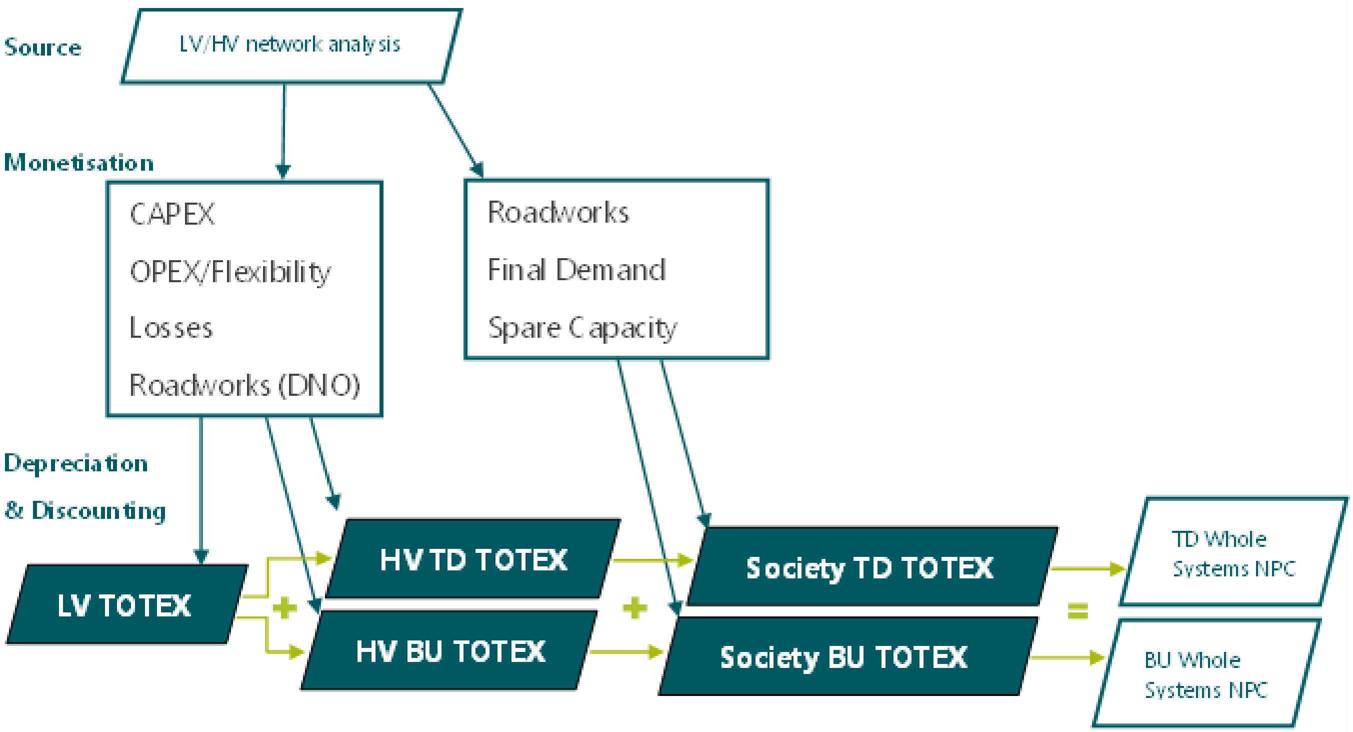

Figure 3: The processes involved in generating results from the WS CBA tool.

The diagram also illustrates how Top Down (TD) and Bottom Up (BU) analysis[1] of the HV network are considered. These two methods of analysis have produced separate results for the HV network which result in distinct societal and whole systems costs. The requirement for both Top Down and Bottom Up analysis reflects the different sources of data available and different approaches to planning for both HV and LV networks. Primary substations typically have monitoring installed at the 11kV feeder circuit breakers but most distribution substations are not monitored. Therefore while the total feeder load is know the loads at different distribution substations are estimated by pro-rating the total load, typically by transformer rating. Thus loads are allocated in a "Top-Down" method when modelling the HV networks. While this method has the advantage that the sum of the distribution loads will equal the monitored load for the feeder, it has the disadvantage that shape of the profiles at the distribution substations are all the same, rather than reflecting the particular mix of customers on that substation.

[1] Top Down analysis uses monitored HV feeder load profiles as a starting point to add the impact of LCT uptake whereas Bottom Up analysis starts by modelling the load at individual distribution substations and aggregating up to HV feeder level.

However when modelling LV networks estimated loads would be built up from knowledge of the connected customers for that substation and profiles for typical customer types. Adding expected customer loads would provide profiles at the distribution substation level that should be more accurate in terms of profile shape but may not sum together along the feeder to equal the observed load at the source circuit breaker. Currently there are advantages and disadvantages for both top-down and bottom-up approaches but over time, as more distribution substations are monitored and smart meter data informs the estimated load profiles at distribution substations, it is likely that the bottom-up approach will become more accurate and will inform HV modelling.

The CBA tool applies depreciation to CAPEX, sums annual costs into TOTEX and discounts the value of future costs in line with best practice in network investment planning and government guidelines. Summing the TOTEX values for the LV network, HV network and society gives a whole system NPC for each tested strategy.

5. Results - Use Case 6: High Solar Deployment in SW Bristol

The results below convey the final iteration of network analysis runs which were able to be conducted in the timescale of the EPIC trial process. Early runs of network analysis identified results which were not consistent with expectations. The processing of the CBA results helped sense check modelling assumptions and modifications to the HV model were followed by subsequent iterations of results, the WP7 learning report documents this in more detail. Examining all specific results and trends in detail has not been possible and so results are discussed where specific information has been available.

This use case assesses the impact on the network and society of a higher deployment of ground mounted solar on the Nailsea Primary.

This use case compares two strategies:

1) A baseline deployment of ground mounted solar on the Nailsea Primary, modelled from the 2019 DFES ‘Consumer Transformation’, 5 MW is deployed by 2050.
2) A higher deployment of Solar on the Nailsea Primary, with up to 55 MW by 2050

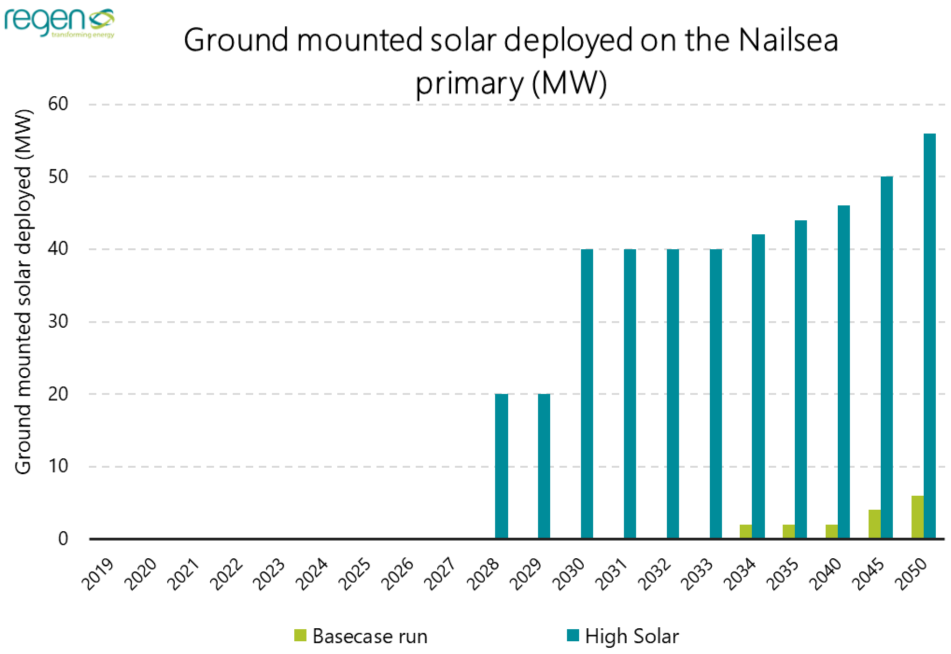

Figure 4: Ground mounted solar deployed in each of the strategies being assessed in Use Case 6

Table 2 below describes the structure of the comparisons made in this report. While absolute costs have been calculated for each strategy, the focus of the report is on the relative costs/benefits of the different strategies and these will be expressed as percentages of the reference strategy.

In this case, **the reference strategy is the "Basecase Solar" variation**, and **percentage increases or savings** for the **"High Solar"** will be reported.

Table 2: The strategies and sensitivities being tested in Use Case 6 and impacts discussed in this report.

Strategy 1: **Basecase Solar** (reference strategy)	Strategy 2: **High Solar**
N/A - Reference strategy	% change in costs/benefits

Table 3, below, illustrates the relative impact of the High Solar strategy on all cost categories. Those cost categories which see variation between 2 – 10% are highlighted in orange, while variations over 10% are highlighted in red. Even greater impacts, over 50%, are indicated by black cells. What is immediately clear is the regularity of large impacts on the electricity network and society. These carry though to create significant Network and Societal TOTEX impacts, and a 2% whole system impact.

Table 3: Results overview for the High Solar strategy on the Nailsea Primary

	CAPEX			OPEX			Losses			Roadworks			Emissions			Spare Capacity		
	LV	HV BU	HV TD	LV	HV BU	HV TD	LV	HV BU	HV TD	LV	HV BU	HV TD	LV	HV BU	HV TD	LV	HV BU	HV TD
Nailsea			120%			-12%			-20%			170%			-10%			-4%

	TOTEX						
	LV	HV BU	HV TD	Societal BU	Societal TD	WHOLE SYSTEM BU	WHOLE SYSTEM TD
Nailsea			53%		-8%		-2%

5.1. CAPEX

CAPEX is equal in the 2020s, before the high solar strategy results in significantly higher CAPEX in all but one year from 2028 to 2050. The largest additional investments are required in the late 2020s and early 2030s when the deployment of Solar begins. The additional investments required in the late 2030s and the 2040s are not as large. This mirrors the deployment seen in figure 4, which grows predominantly in the late 2020s and early 2030s. **The results is a 120% increase in total HV CAPEX requirements by 2050.**

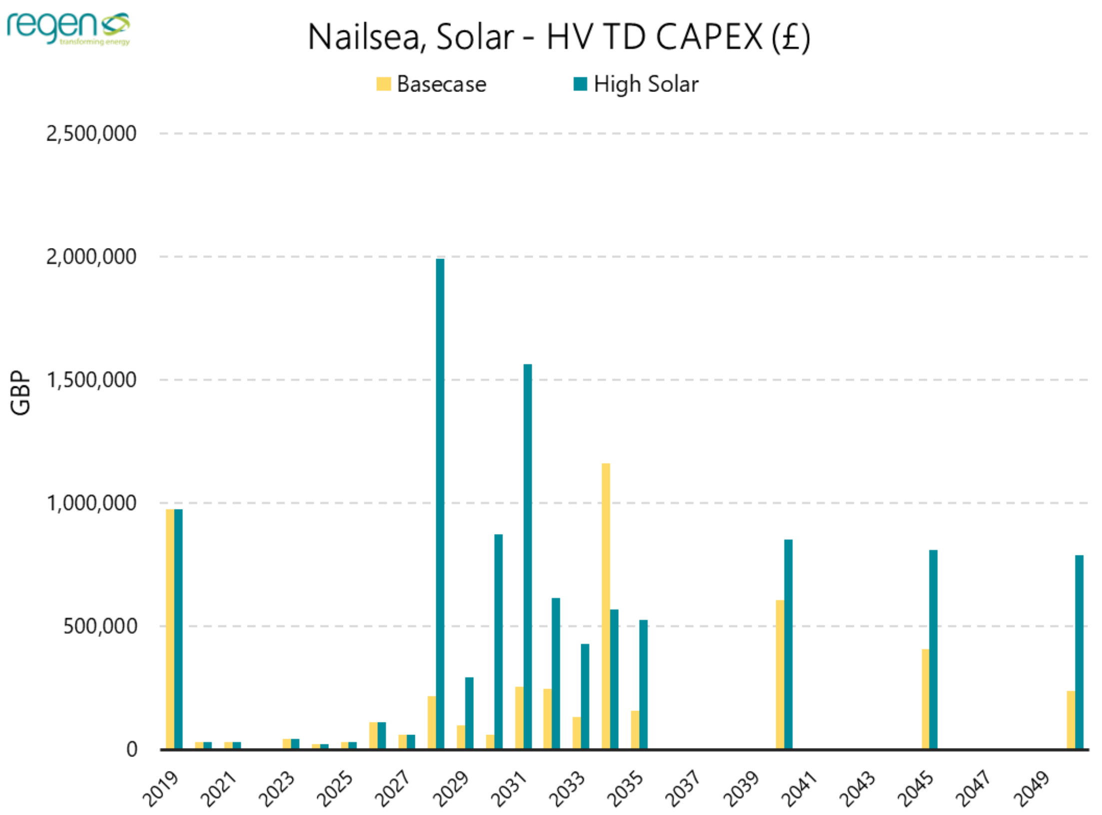

Figure 5: HV CAPEX by year on the Nailsea Primary, from top down analysis.

5.2. OPEX

As with CAPEX, the two strategies have identical OPEX in the early-mid 2020s. The High Solar strategy results in OPEX savings from 2028-2040. This could be as a result the additional CAPEX investment in the HV network increasing network capacity and reducing the need to procure flexibility services. OPEX costs are then very similar in the 2040s. **By 2050 the high solar strategy has resulted in a 12% saving in total HV OPEX.**

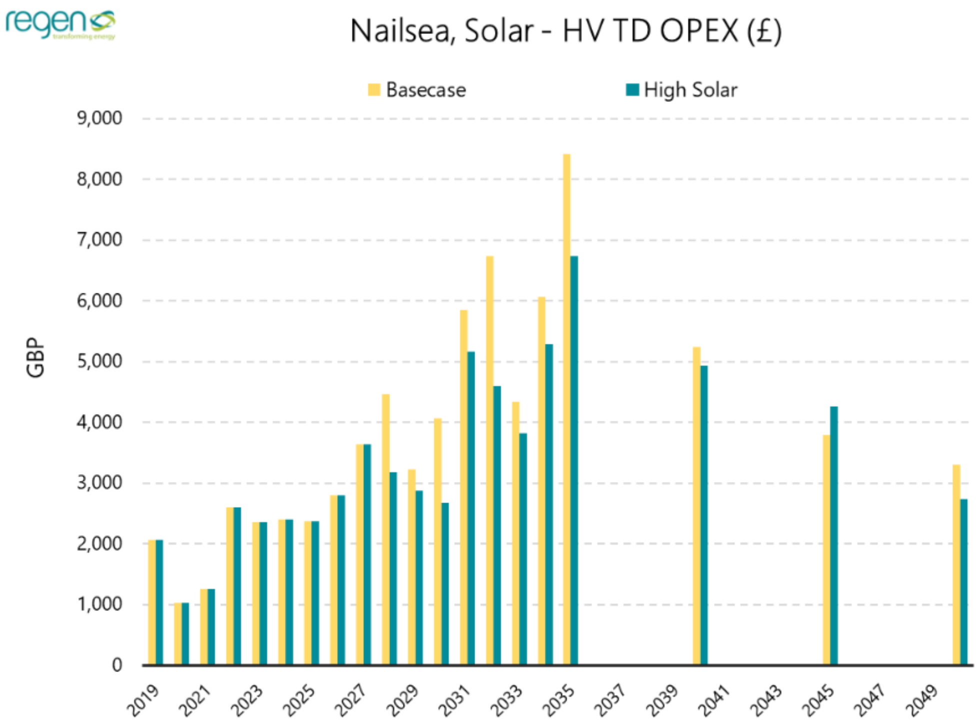

Figure 6: HV OPEX by year on the Nailsea Primary, from top down analysis

5.3. Losses

The High Solar strategy results in lower HV losses from 2028 onwards, these savings are consistent out to 2050, by which time they have resulted in a **20% saving in total HV losses.**

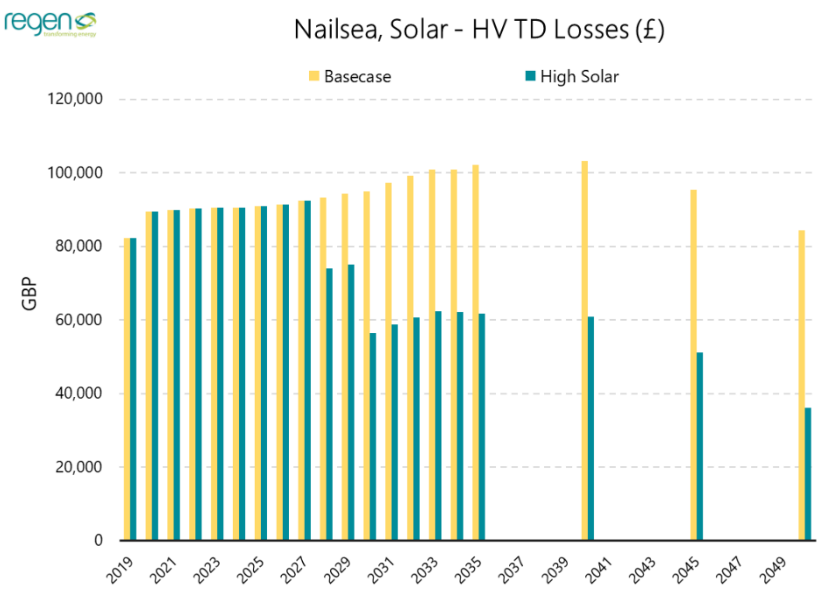

Figure 7: HV Losses by year on the Nailsea Primary, from top down analysis.

5.4. Roadworks

Mirroring the additional CAPEX required on HV network intervention, the High Solar strategy results in higher HV roadworks through the 2030s and 2040s. These are relatively consistent year on year, and result in **a total increase of 170% in the cost of roadworks by 2050.**

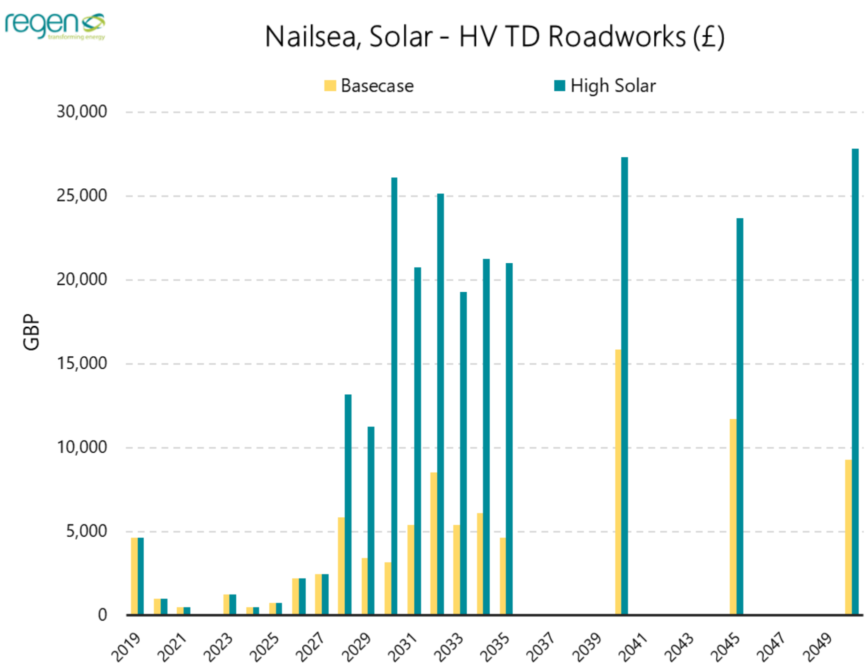

Figure 8: HV Roadworks by year on the Nailsea primary, from top down analysis

5.5. Emissions (Final Demand)

The high solar strategy reduces demand on the HV network from 2028 onwards. The impact on the HV network demand reflects the degree of GM solar installed at any point in time so therefore the changes in demand profile reflect the GM solar deployment assumptions as shown in figure 4. This gives large increases circa 2028 and 2030 followed by diminishing annual increases up to 2050. These savings decrease as the carbon factor of the grid decreases, and result in a **10% cost of emissions saving by 2050.**

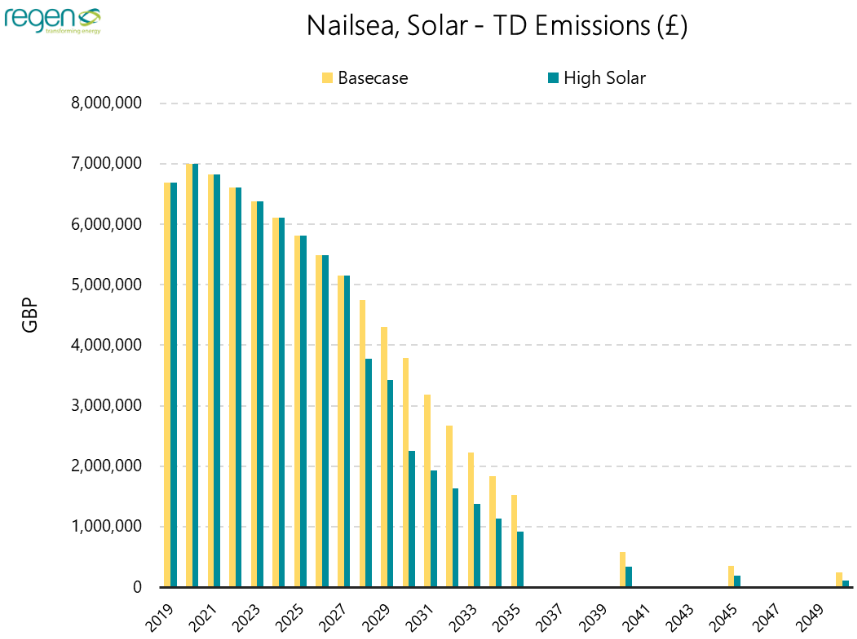

Figure 9: Emissions by year from the Nailsea primary, from top down analysis

5.6. Spare Capacity

The high solar strategy releases significantly more spare capacity on the HV network in 2028, 2030 and 2031. This is a result of the large additional CAPEX investments in the network in this period. The basecase sees more spare capacity unlocked in 2030s and 2040s, as it's later large CAPEX interventions occur and this offsets these gains. **By 2050 the high solar strategy has resulted in a total additional spare capacity benefit of 4%.**

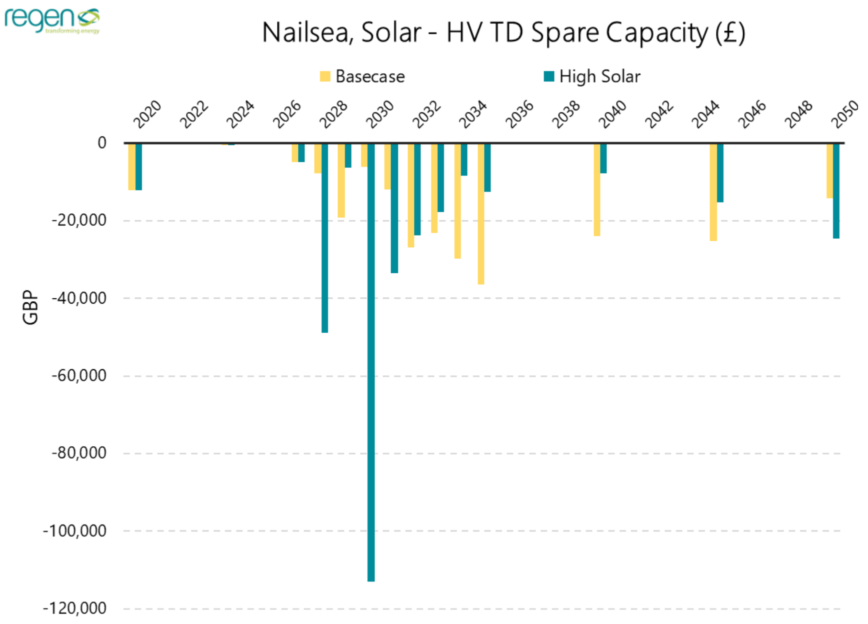

Figure 10: HV Spare Capacity by year on the Nailsea primary, from top down analysis

5.7. TOTEX

Summing the HV network costs outlined above gives HV TOTEX which is then subject to discounting treatment. The high solar strategy results in increased HV TOTEX from 2028 onwards. This is driven primarily by increased CAPEX requirements on the network and supplemented by additional roadworks. Savings in OPEX and reduced losses do offset these increases to a small degree. **By 2050 an additional 53% of HV TOTEX is required for the high solar strategy, a £2.5m increase in expenditure for the electricity network.**

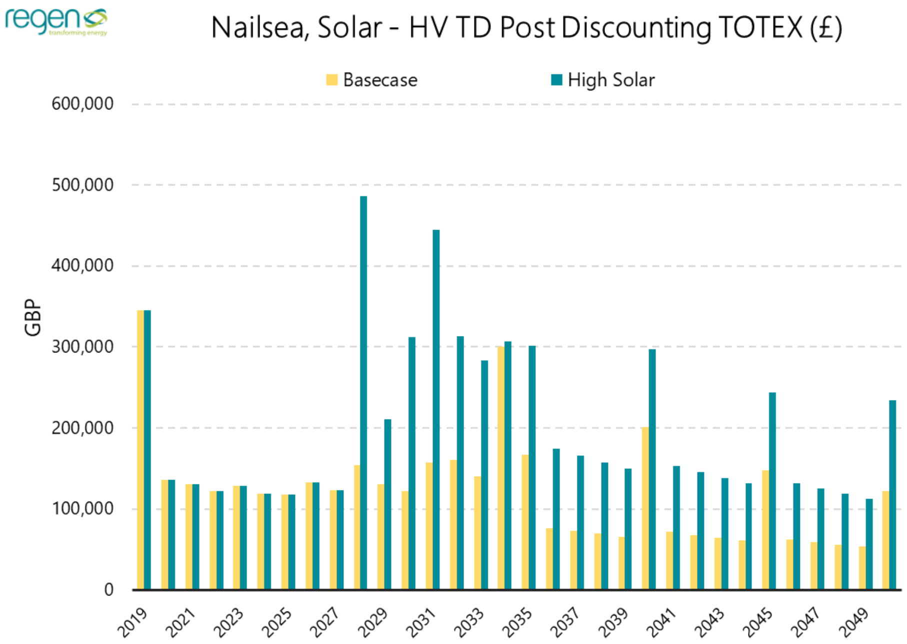

Figure 11: HV TOTEX by year on the Nailsea primary, from top down analysis

Societal TOTEX is formed of the societal cost of roadworks, emissions and spare capacity. The high solar strategy results in societal savings from 2028 to 2050, these are driven by reduced emissions from the HV network. The large increases in roadworks for the high solar strategy goes some way in offsetting this saving, but only forms approximately 1/8th of its value. The valuation of Spare Capacity in this CBA means the benefits of additional spare capacity for the high solar strategy are relatively insignificant in this societal TOTEX sum, forming approximately 1/100th of the emissions saving.

By 2050 the high solar strategy has resulted in 8% savings in Societal TOTEX. In absolute terms this is a £5m saving. Socialising this to all 10,000 customers on the Nailsea primary, the result is a $482 saving per customer.

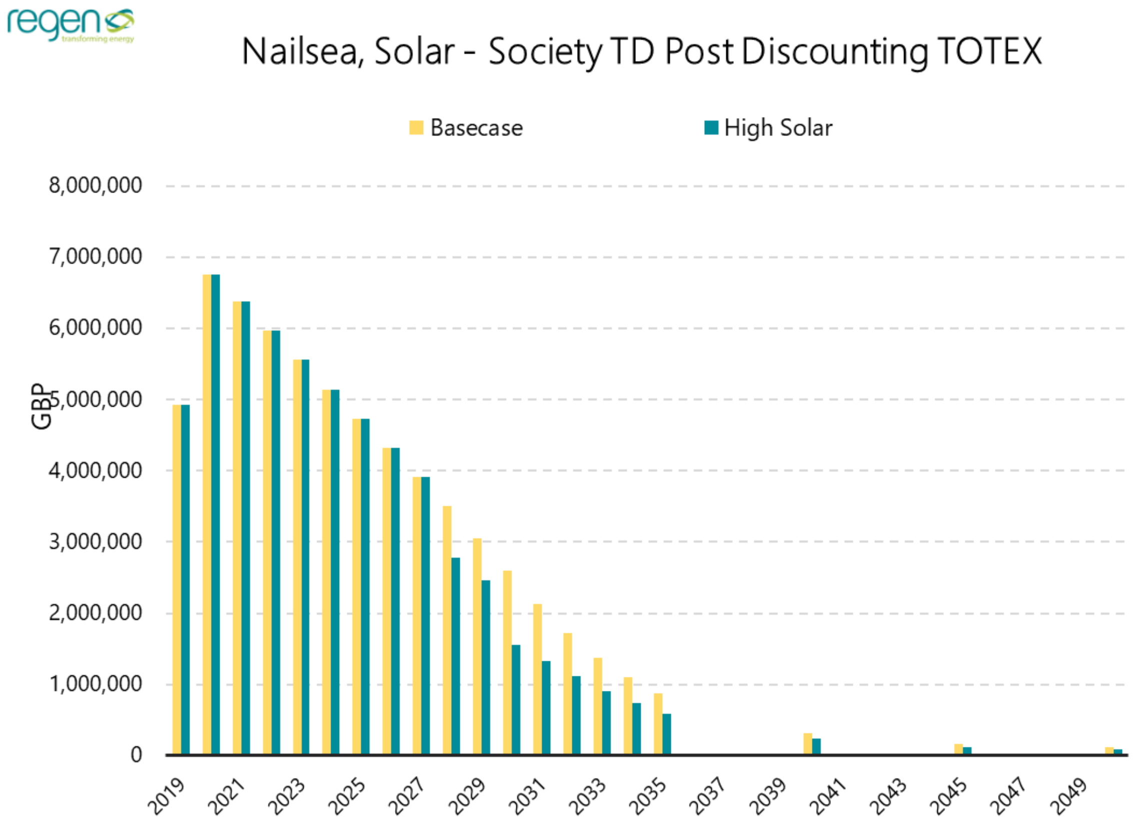

Figure 12: Societal TOTEX by year on the Nailsea primary, from top down analysis

5.8. Whole Systems

Combining the Network and Societal TOTEX values results in a Whole Systems Net Present Cost. In this use case, the high solar strategy requires an additional £2.5m investment in the HV network, but delivers a £5m to society. As a result, the high solar use case delivers a whole system saving of £2.5m. **This represents a 2.2% saving in whole system expenditure over the base case strategy.**

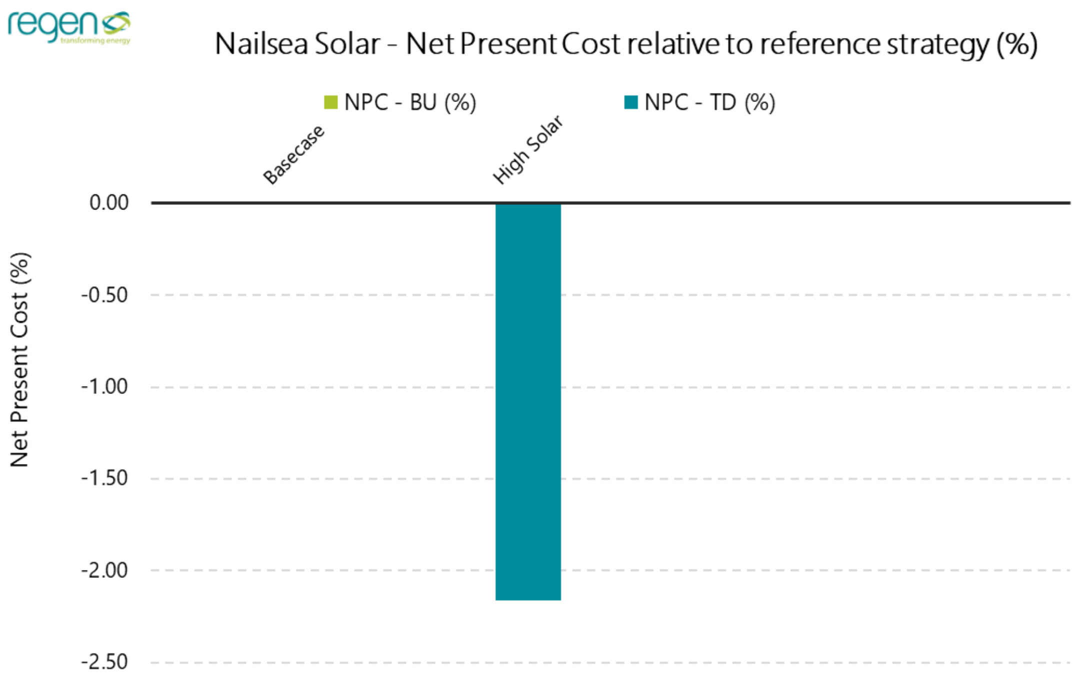

Figure 13: Relative Net Present Cost of the base case and high solar strategy.