Powercor

Regulatory Investment Test for Distribution Melton and Bacchus Marsh

Draft project assessment report

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1 Summary

This draft project assessment report has been prepared by Powercor Australia Limited (**Powercor**) in accordance with the Regulatory Investment Test for Distribution (**RIT-D**) requirements of the National Electricity Rules (**the Rules**).[1] This draft project assessment report follows our non-network options report, published in August 2014.

The purpose of this draft project assessment report is to consult on the credible options to address the following network constraints:

- existing capacity constraints at Melton (**MLN**) and Bacchus Marsh (**BMH**) zone substations; and
- existing capacity constraint on the Brooklyn terminal station (**BLTS**) to BMH 66 kV sub-transmission line.

Based on the analysis presented in this report, and subject to any further information provided by interested parties in response to this paper, our preferred option is to install a third transformer in the MLN zone substation, as well as a new 22kV feeder (partially built using 66kV construction) to transfer 5 MW of BMH customers to MLN.

The estimated total direct capital cost of the project is $6.7 million.

Further feedback is now being sought from stakeholders including Registered Participants, the Australian Energy Market Operator (**AEMO**), non-network providers, interested parties as well as persons on our demand side engagement register. Submissions are being sought by 18th March 2016.

We will consider all submissions received in relation to the draft project assessment report before preparing a final project assessment report.

Should the preferred option have an estimated capital cost of less than $20 million, we may publish the final project assessment report within the Distribution Annual Planning Report (**DAPR**). We will publish the 2015 DAPR by 31 December 2015.

[1] Specifically, version 73 of the Rules, clause 5.17.4.

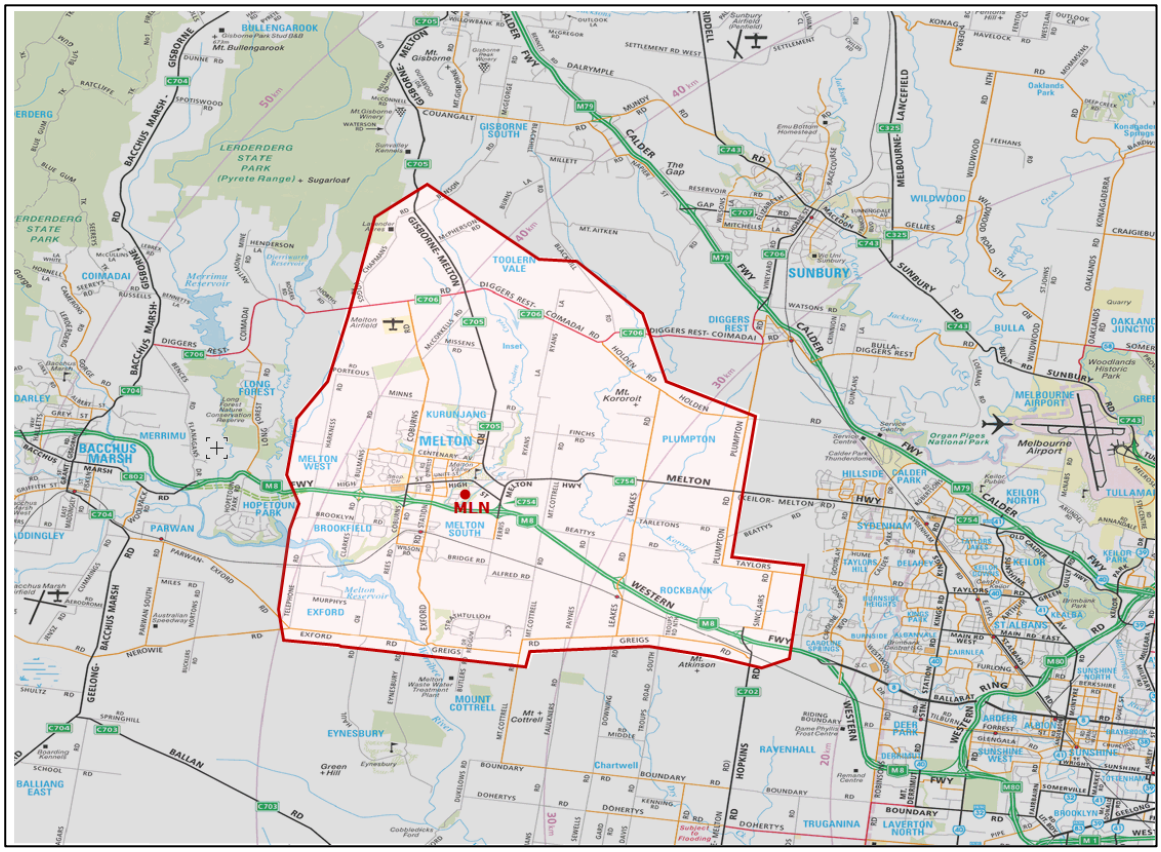
2 Background network information

This section sets out background information regarding the network in the Melton and Bacchus Marsh areas.

2.1 Melton

The Melton zone substation (**MLN**) is located on the corner of Graham Street and Reserve Road, in Melton. MLN provides electricity supply to a total of 21,675 customers, including 20,453 domestic, 1,007 commercial, 145 industrial, and 70 agricultural customers. The areas supplied include the suburbs of Melton, Melton South, Melton West, Kurunjang, Rockbank and Brookfield. Figure 2.1 shows the area supplied by MLN at a high level.

Figure 2.1 Geographical area supplied by Melton zone substation



Source: Reproduced from the Melway Street Directory with permission, overlay locations of zone substation and zone substation coverage area added by Powercor.

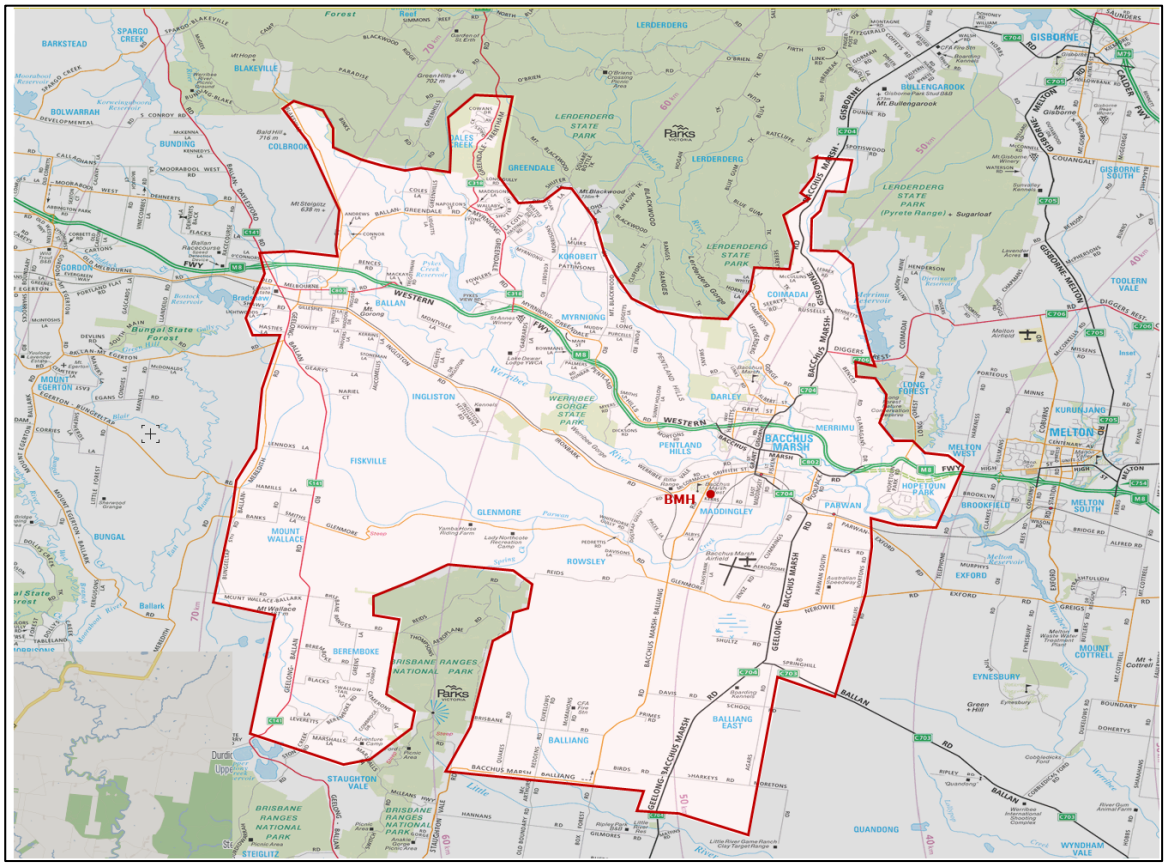
MLN is currently served by two 66kV sub-transmission lines from the Keilor Terminal Station (**KTS**). The zone substation is a fully switched station consisting of two 20/27/33 MVA 66/22kV transformers supplying two indoor 22 kV buses with eight distribution feeders.

The zone substation predominately experiences summer afternoon-into-evening peak demand, driven by residential customers and supported by a strong commercial demand during the day.

2.2 Bacchus Marsh

The Bacchus Marsh zone substation (**BMH**) is located on the corner of Bacchus Marsh-Balliang Road and Kerrs Road, Maddingley. BMH provides electricity supply to a total of 10,566 customers, including 9,431 domestic, 719 commercial, 169 industrial, and 247 agricultural customers. The suburbs supplied include Bacchus Marsh, Maddingley, Darley, Greendale, Ballan and Myrniong. Figure 2.2 below shows the area supplied by BMH.

Figure 2.2 Geographical area supplied by Bacchus Marsh zone substation



Source: Reproduced from the Melway Street Directory with permission, overlay locations of zone substation and zone substation coverage area added by Powercor.

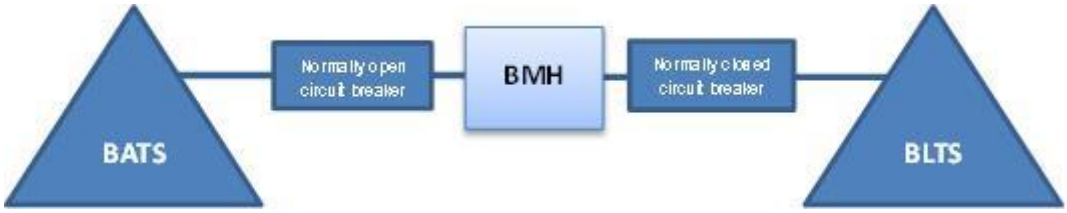
BMH is currently supplied by a 66 kV sub-transmission line from the Brooklyn terminal station (**BLTS**) with backup supply via a 66 kV sub-transmission line from the Ballarat terminal station (**BATS**) via an auto changeover scheme at BMH. The zone substation is a banked station consisting of two 10/13.5 MVA 66/22 kV transformers supplying two 22 kV buses with four distribution feeders.

The zone substation experiences both summer evening and winter hot water load peak.

2.3 BLTS to BMH sub-transmission line

As noted above, the BMH zone substation is supplied by a 66 kV sub-transmission line from BLTS. The total length of the BLTS-BMH 66kV line is 56.4kms, with the circuit consisting of a mixture of aluminium (AAC, ACSR) and copper (Cu, Cd) conductors. The backup supply BATS-BMH 66kV line is 52kms in length, with the circuit consisting of a mixture of aluminium (AAC) and copper (Cu, Cd) conductors.

Figure 2.3 Single line diagram of the BLTS-BMH 66kVsub-transmission line



3 Description of the identified need

We adopt a probabilistic approach to planning our zone substation and sub-transmission asset augmentations. This involves estimating the probability of an outage occurring within the peak loading period, and weighting the expected cost that will be incurred if no action is taken to address the constraint.

3.1 Probability of an outage occurring within the peak loading period

The probability of an outage occurring within the peak loading period is based on an assessment of forecast maximum demand and load, relative to the capacity of the relevant infrastructure. For this draft project assessment report, the relevant infrastructure is assessed under the following two scenarios:

- probability of maximum demand exceeding the N-1 rating of the infrastructure; and
- probability of maximum demand exceeding the N rating of the infrastructure.

Our forecasts of maximum demand and load used in our analysis have been developed from a reconciliation of bottom-up forecasts based on network data, and top-down econometric forecasts.

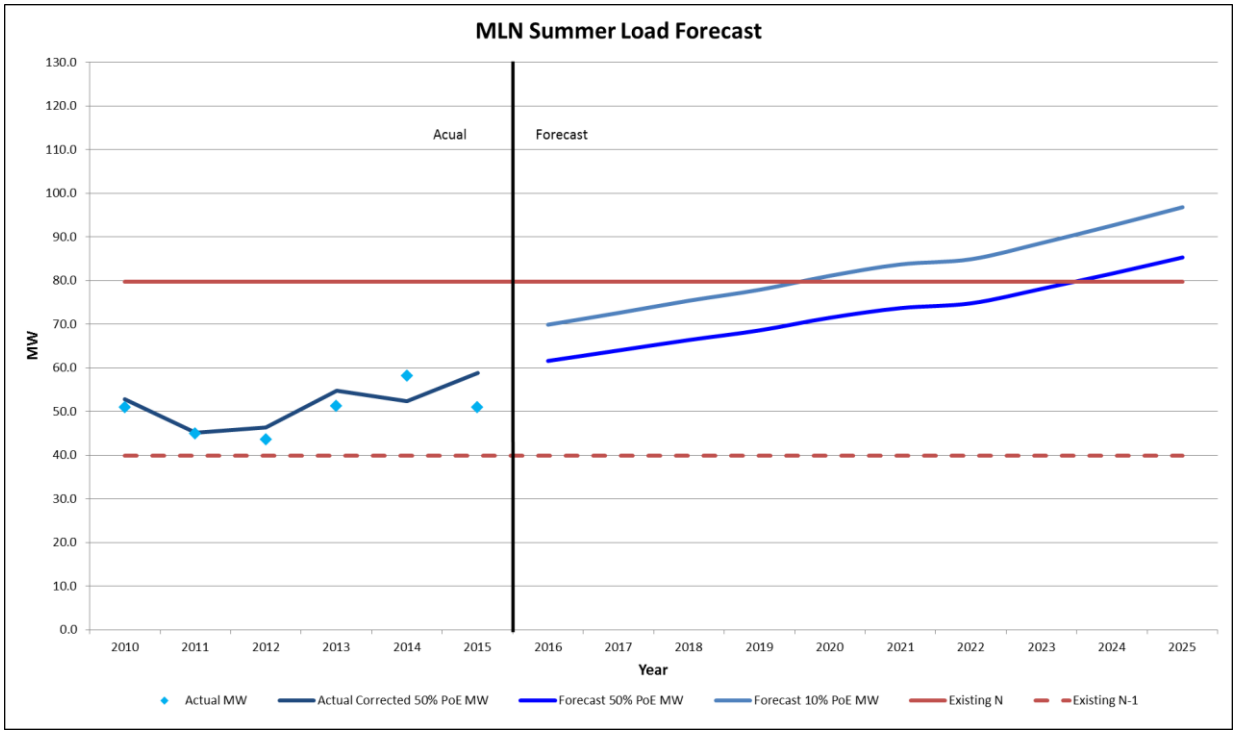
Bottom-up forecasts are developed from historical demand values that are trended forward, with the addition of known and predicted loads that may be connected to the network in future. This includes taking into account the number of customer connections and the estimated total output of known embedded generating units in the forecast period.

Top–down econometric forecasts are prepared for us by the Centre for International Economics (**CIE**), which is an independent economic forecaster. These forecasts are based on statistical modelling that derives historical relationships between various economic and environmental variables and demand. This is consistent with the best practice methodology used for forecasting by the Australian Energy Market Operator (**AEMO**).

3.1.1 Probability of an outage occurring at MLN

Figure 3.1 shows the historical and forecast summer 50 per cent and 10 per cent probabilities of exceedance (**PoE**) for maximum demand against the MLN zone substation N and N-1 ratings.

Figure 3.1 Forecast maximum demand against the station ratings at MLN



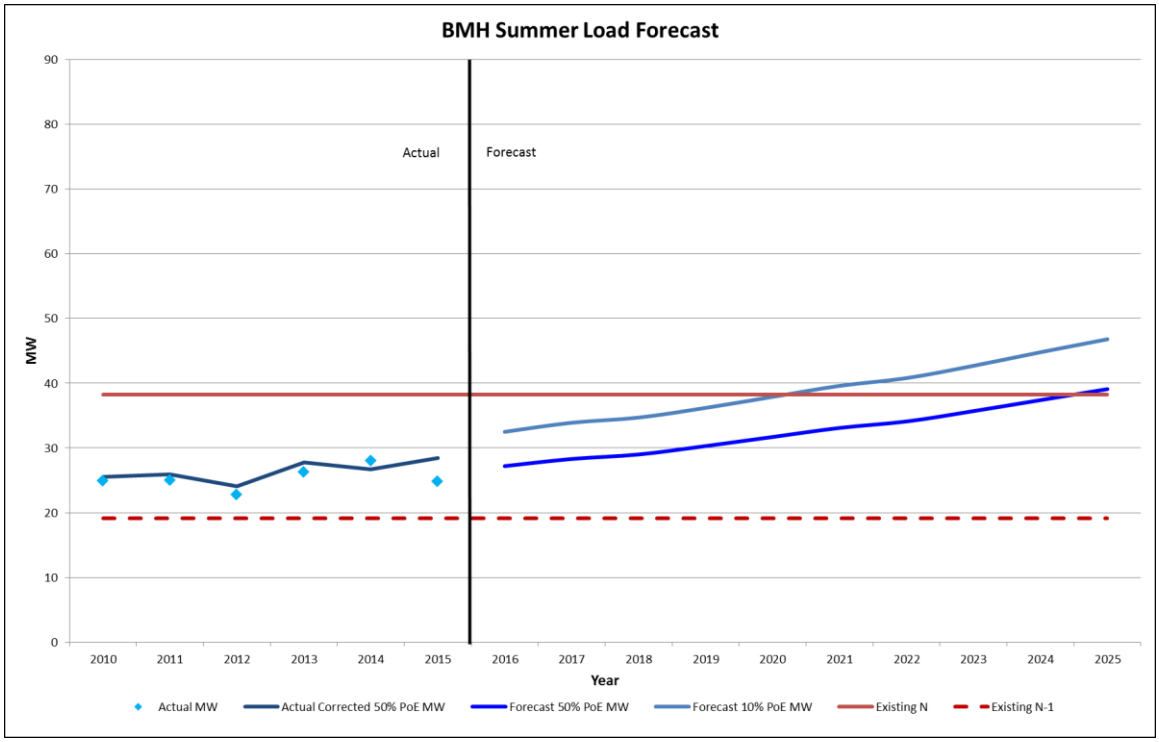
Based on the above, we identified the following issues at MLN:

- MLN is currently loaded above the station N-1 rating for actual and forecast 50 per cent PoE. As a consequence, customers are already exposed to the risk of supply interruptions in the event of a failure of a single transformer at the zone substation.
- By 2020, at the 10 per cent PoE maximum demand level, there will be insufficient capacity at the zone substation to supply peak demand with all plant in service.
- At the 50 per cent PoE load forecast, with one transformer out of service (N-1 rating), customers will face a supply interruption due to insufficient capacity at the station unless action is taken to reduce demand or increase capacity at MLN.
- Only limited load transfer capability exists between MLN zone substation and the neighbouring zone substations at BMH and Sunshine (**SU**). As a result, customers could potentially be left without supply until capacity in the neighbouring network becomes available. As forecast load growth continues, the available transfer capability diminishes, leaving a greater number of customers exposed to the risk of a supply interruption due to insufficient network capacity.
- Strong load growth is expected in the Rockbank East, Plumpton and Koroit areas following the release of the new Precinct Structure Plans (**PSP**) by the Melbourne Planning Authority (**MPA**).

3.1.2 Probability of an outage occurring at BMH

Figure 3.2 shows the historical and forecast summer 50 per cent and 10 per cent PoE for maximum demand against the BMH zone substation N and N-1 ratings.

Figure 3.2 Forecast maximum demand against the station ratings at BMH



Based on the above, we identified the following issues at BMH:

- BMH is approaching the N cyclic rating of the substation, and is now already above the N-1 cyclic rating. As a consequence, customers are exposed to supply interruptions in the event of a failure of a single transformer at the zone substation.
- By 2020, at the 10 per cent PoE demand level, there will be insufficient capacity at the zone substation to supply all demand with all plant in service.
- At the 50 per cent PoE load forecast, with one transformer in service (N-1 rating), customers will face a supply interruption due to insufficient capacity at the station, unless action is taken to reduce demand or increase capacity at BMH.
- Limited load transfer capability exists between BMH zone substation and the neighbouring zone substations at MLN and Ballarat North (**BAN**). As a result, customers could potentially be left without supply until capacity in the neighbouring network becomes available. As forecast load growth continues, the available transfer capability diminishes, leaving a greater number of customers exposed to the risk of supply interruption due to insufficient network capacity.

3.1.3 Probability of an outage occurring on BLTS-BMH 66kV line

The forecast peak demand at BMH zone substation will also cause the BLTS-BMH 66kV sub-transmission line to exceed its N line rating. Further increases in load above the N rating will cause the transformers at BMH to reach their maximum voltage boost tap. This leaves a

potential for the distribution voltage on the 22kV network to fall below the Electricity Distribution Code (**Code**) limit.

Under normal system conditions with BLTS-BMH in service, customers face an expected supply interruption due to insufficient capacity of the 66kV line unless action is taken to reduce demand or increase capacity of BLTS-BMH.

3.2 Expected cost if no action is taken to address the constraint

To estimate the expected costs that will be incurred if no action is taken to address a network constraint, we weight the expected costs against the probability of an outage occurring within the peak loading period. To calculate the expected costs, the expected unserved energy (in MWh) that would not be supplied in the event of a transformer failure is multiplied by the probability of a transformer failure.

The expected unserved energy is expressed as a dollar value by multiplying the energy quantity by the value of customer reliability (**VCR**). This approach facilitates a comparison of the economic impact of supply interruptions. For this draft project assessment report, we have calculated the expected unserved energy using the assumptions set out in Table 3.1.

Table 3.1 Assumptions used to evaluate load at risk, expected unserved energy, and hours at risk

Variable	Assumption
Growth in forecast demand (base case)	MLN: 3.4 per cent annual growth in load forecast BMH: 2.9 per cent annual growth in load forecast BLTS-BMH: 3.2 per cent annual growth in load forecast
Weighting of demand forecasts to estimate expected unserved energy	Total unserved energy estimated by taking a 70 per cent weighting of expected unserved energy at the 50th percentile forecast and 30 per cent weighting of expected unserved energy at the 10th percentile forecast
Value of Customer Reliability (VCR)	MLN: $35,004 per MWh BMH: $35,951 per MWh Note: Based on the VCR data published by AEMO, the VCR is calculated based on the proportion of commercial, industrial, residential and agricultural customers supplied by the zone substation.
Transformer failure rate	1 per cent per annum A major failure is expected to occur once per 100 transformer-years
Duration of transformer outage	1900 hours A total of 2.6 months is required to repair/replace the transformer, during which time the transformer is out of service
Sub-transmission line failure rate	0.05 per cent per annum

Variable	Assumption
66kV Line Duration of outage	8 hours

Our calculations of expected unserved energy, based on the assumptions outlined above, are set out in Table 3.2 to Table 3.14. These calculations are presented separately for both the N and N-1 ratings at MLN, BMH and BLTS-BMH line, and for load forecasts depicting the 50 per cent and 10 per cent PoE.

Table 3.2 MLN: load at risk and expected unserved energy for N rating at 50 per cent PoE load forecast

Metric	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Load above N Rating (%)	0%	0%	0%	0%	0%	0%	1%	5%	10%	15%
Load at risk (MVA)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.1	5.9	9.8
Energy at risk (MWh)	0	0	0	0	0	0	0	3	25	83
Expected unserved energy ($ 000's)	0	0	0	0	0	0	0	90	858	2,852
Hours at risk	0	0	0	0	0	0	0	3	10	22

Table 3.3 BMH: load at risk and expected unserved energy for N rating at 50 per cent PoE load forecast

Metric	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Load above N Rating (%)	0%	0%	0%	0%	0%	0%	0%	2%	6%	11%
Load at risk (MVA)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.7
Energy at risk (MWh)	0	0	0	0	0	0	0	0	0	3
Expected unserved energy ($ 000's)	0	0	0	0	0	0	0	0	0	108
Hours at risk	0	0	0	0	0	0	0	0	0	3

Table 3.4 BLTS-BMH: load at risk and expected unserved energy for N rating at 50 per cent PoE load forecast

Metric	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Load above N Rating (%)	3%	11%	16%	21%	30%	35%	39%	43%	48%	53%
Load at risk (MVA)	0.0	1.2	2.8	4.2	7.3	8.7	11.1	14.0	17.1	20.2
Energy at risk (MWh)	0	1	7	20	80	121	175	249	363	545
Expected unserved energy ($ 000's)	0	39	266	736	2,889	4,345	6,276	8,966	13,039	19,599
Hours at risk	0	2	5	11	27	36	48	67	100	153

Table 3.5 MLN: load at risk and expected unserved energy for N rating at 10 per cent PoE load forecast

Metric	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Load above N Rating (%)	0%	0%	0%	3%	7%	11%	12%	17%	23%	28%
Load at risk (MVA)	0.0	0.0	0.0	2.2	5.8	8.5	9.8	13.8	18.1	22.7
Energy at risk (MWh)	0	0	0	3	24	58	82	183	339	567
Expected unserved energy ($ 000's)	0	0	0	101	826	2,000	2,832	6,301	11,673	19,504
Hours at risk	0	0	0	3	10	17	22	33	50	68

Table 3.6 BMH: load at risk and expected unserved energy for N rating at 10 per cent PoE load forecast

Metric	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Load above N Rating (%)	0%	0%	0%	0%	2%	6%	10%	15%	21%	26%
Load at risk (MVA)	0.0	0.0	0.0	0.0	0.6	2.4	3.7	5.7	7.9	10.1
Energy at risk (MWh)	0	0	0	0	0	6	17	50	106	190
Expected unserved energy ($ 000's)	0	0	0	0	14	222	594	1,780	3,802	6,844
Hours at risk	0	0	0	0	1	6	11	22	36	53

Table 3.7 BLTS-BMH: load at risk and expected unserved energy for N rating at 10 per cent PoE load forecast

Metric	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Load above N Rating (%)	8%	17%	22%	27%	38%	43%	47%	52%	58%	63%
Load at risk (MVA)	2.7	5.4	7.2	9.8	15.6	18.7	21.9	25.2	28.7	32.3
Energy at risk (MWh)	7	38	77	128	300	439	653	966	1402	1993
Expected unserved energy ($ 000's)	248	1,371	2,766	4,612	10,798	15,770	23,468	34,728	50,396	71,650
Hours at risk	5	17	27	40	81	126	184	258	346	458

Table 3.8 MLN: load at risk and expected unserved energy for N-1 rating at 50 per cent PoE load forecast

Metric	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Load above N Rating (%)	66%	73%	79%	85%	93%	99%	102%	111%	120%	130%
Load at risk (MVA)	24.3	26.9	29.4	32.1	36.0	39.2	40.1	44.8	50.0	55.0
Energy at risk (MWh)	1,700	2,154	2,679	3,230	4,077	4,831	5,247	6,714	8,708	11,362
Expected unserved energy ($ 000's)	58,450	74,063	92,120	111,080	140,187	66,145	180,422	230,891	299,450	390,721
Hours at risk	219	260	306	352	430	505	549	704	933	1,244

Table 3.9 BMH: load at risk and expected unserved energy for N-1 rating at 50 per cent PoE load forecast

Metric	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Load above N Rating (%)	55%	61%	65%	72%	80%	88%	94%	103%	113%	122%
Load at risk (MVA)	14.5	16.6	17.9	20.5	23.1	26.0	27.8	31.0	34.4	37.6
Energy at risk (MWh)	1,079	1,599	1,992	2,964	4,256	6,115	7,455	10,314	14,003	17,957
Expected unserved energy ($ 000's)	38,802	57,490	71,606	106,549	153,024	219,830	268,035	370,788	503,430	645,578
Hours at risk	129	166	191	249	335	460	576	842	1198	1607

Table 3.10 BLTS-BMH: load at risk and expected unserved energy for N-1 rating at 50 per cent PoE load forecast

Metric	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Load above N Rating (%)	16%	24%	30%	35%	46%	51%	56%	61%	66%	71%
Load at risk (MVA)	2.2	4.7	6.3	7.7	10.8	12.2	13.6	15.0	16.5	18.1
Energy at risk (MWh)	5	38	80	214	530	837	1,258	1,815	2,541	3,470
Expected unserved energy ($ 000's)	192	1,354	2,860	7,678	19,068	30,103	45,240	65,256	91,341	124,751
Hours at risk	6	24	44	110	205	284	376	486	622	789

Table 3.11 MLN: load at risk and expected unserved energy for N-1 rating at 10 per cent PoE load forecast

Metric	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Load above N Rating (%)	84%	91%	99%	106%	114%	121%	125%	135%	145%	157%
Load at risk (MVA)	34.7	38.4	41.7	45.1	49.5	53.1	54.1	59.4	65.2	70.8
Energy at risk (MWh)	3,970	4,919	6,049	7,295	9,303	11,169	12,153	15,759	20,345	25,713
Expected unserved energy ($ 000's)	136,537	169,173	208,033	250,857	319,918	384,077	417,926	541,939	699,653	884,230
Hours at risk	397	487	603	740	978	1,207	1,311	1,725	2,164	2,528

Table 3.12 BMH: load at risk and expected unserved energy for N-1 rating at 10 per cent PoE load forecast

Metric	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Load above N Rating (%)	73%	80%	85%	93%	103%	112%	119%	129%	141%	152%
Load at risk (MVA)	21.5	23.9	25.4	28.3	31.3	34.6	36.7	40.3	44.2	47.8
Energy at risk (MWh)	2,917	4,110	5,025	7,237	10,150	14,045	16,863	22,329	28,825	35,369
Expected unserved energy ($ 000's)	104,605	147,383	180,204	259,540	364,015	503,694	604,752	800,757	1,033,739	1,268,400
Hours at risk	1,065	1,461	1,762	2,385	3,094	3,840	4,292	5,007	5,653	6,164

Table 3.13 BLTS-BMH: load at risk and expected unserved energy for N-1 rating at 10 per cent PoE load forecast

Metric	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Load above N Rating (%)	21%	31%	37%	42%	54%	60%	65%	71%	76%	82%
Load at risk (MVA)	10.4	15.1	17.9	21.9	27.6	30.8	34.0	37.3	40.8	44.3
Energy at risk (MWh)	143	412	629	1,230	2,201	3,040	4,116	5,463	7,103	9,050
Expected unserved energy ($ 000's)	5,134	14,810	22,610	44,233	79,125	109,287	147,973	196,395	255,363	325,354
Hours at risk	83	171	228	366	547	694	884	1,094	1,320	1,548

Table 3.14 Expected unserved energy for combined zone substations MLN and BMH, and 66kV sub-transmission line BLTS-BMH

Expected unserved energy	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
50 per cent POE N ($ 000's)	25	463	1,215	2,178	5,595	7,854	10,999	15,876	24,124	37,248
50 per cent POE N-1 ($ 000's)	96,354	133,161	168,078	230,688	324,207	433,923	518,698	703,521	945,097	1,228,377

Expected unserved energy	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
10 per cent POE N ($ 000's)	1,062	3,281	5,531	8,410	18,934	28,652	41,894	63,151	93,129	133,621
10 per cent POE N-1 ($ 000's)	251,901	344,204	429,676	585,645	810,902	1,059,391	1,247,242	1,634,224	2,103,636	2,615,702
AEMO weighted ($ 000's)	143,355	197,782	249,067	341,223	479,813	635,657	757,529	1,012,790	1,337,484	1,710,734

4 Assessment of credible options

This section outlines our assessment of the credible options we consider address the identified need. Consistent with the Rules, this assessment includes cost-benefit analysis of several reasonable scenarios of future supply and demand. These scenarios enable the sensitivity of the key variables and investment decision signals to be tested.

4.1 Credible options

For the purpose of this draft project assessment report, we considered the potential network options set out in Table 4.1. The potential credible network and non-network options were first discussed in our non-network options report, published in August 2014 (and available on our website). In response to our non-network options report, we received a limited number of informal enquires relating to the network constraint. We did not receive, however, any formal submissions of a non-network proposal.

Table 4.1 Potential credible network options

Option	Description
0	Do nothing: This option provides the base case against which the net market benefits of all other options are evaluated.
1	This option includes: • installing a third transformer (25/33 MVA) at MLN zone substation with a third 22kV indoor bus in 2016 and 2017, to be commissioned prior to the 2017/18 summer; • installing a new 22 kV feeder at MLN to tie into the existing network and offload BMH by 5 MW in 2016 and 2017, to be commissioned prior to the 2017/18 summer; • installing a third transformer (25/33 MVA), and associated works at BMH zone substation in 2021 and 2022; and • augmenting the existing BLTS-BMH 66kV sub-transmission line in 2021 and 2022. This option will: • increase the N and N-1 rating at MLN zone substation, allowing for future load growth and development and reduce the load at risk under a N-1 contingency event at MLN; • reduce the N-1 load at risk at BMH zone substation; and • reduce the N rating load at risk on the BLTS-BMH 66kV line. The estimated total direct capital and operating costs of this option is $23.5 million ($15.5 million present value in $2015). Operation and maintenance costs are estimated at 1 per cent of the capital costs annually.

Option	Description
2	This option includes: • installing a third transformer (25/33 MVA) at MLN zone substation with a third 22kV indoor bus in 2016 and 2017, to be commissioned prior to the 2017/18 summer; • installing a third transformer (25/33 MVA), and associated works at BMH zone substation in 2016 and 2017; and • augmenting the existing BLTS-BMH 66kV sub-transmission line in 2016 and 2017. This option will: • increase the N and N-1 rating at MLN zone substation, allowing for future load growth and development and reduce the load at risk under a N-1 contingency event at MLN; • increase the N and N-1 rating at BMH zone substation, and reduce the load at risk under a N-1 contingency event at BMH; and • reduce the N rating load at risk on the BLTS-BMH 66kV line. This project is similar in scope to option one, but it involves the advancement of the installation of a new transformer at BMH to 2016 and 2017, and the advancement of the augmentation of the BLTS-BMH 66kV line to 2016, 2017, as a result of not installing an additional feeder at MLN to offload BMH. The estimated total direct capital and operating costs of this option is $23.6 million ($17.4 million in $2015 present value), and the advancement of the works at BMH means that the costs are higher than option one in present value terms. Operation and maintenance costs are estimated at 1 per cent of the capital costs annually.
3	This option includes: • installing a third transformer (25/33 MVA) at MLN zone substation with a third 22kV indoor bus in 2016 and 2017, to be commissioned prior to the 2017/18 summer; • installing a new 66 kV feeder operating at 22 kV from MLN towards BMH, to offload BMH by 5 MW in 2016 and 2017; • installing a third transformer (25/33 MVA), and associated works at BMH zone substation in 2021 and 2022; and • install the remaining section of 66kV line from MLN to BMH in 2022. This will become a new sub-transmission line from MLN-BMH in lieu of augmenting the BLTS BMH line and transfer 5MW from MLN back to BMH. This option will: • increase the N and N-1 rating at MLN zone substation, allowing for future load growth and development and reduce the load at risk under a N-1 contingency event at MLN; • reduce the N-1 load at risk at BMH zone substation; and • reduce the N rating load at risk on the BLTS-BMH 66kV line. This project is similar in scope to option one, but it involves the part construction of a 66kV feeder, initially operated as 22kV, to offload BMH by 5 MW. In 2020 and 2021, construction of the remaining sections of the 66kV feeder tying BMH to MLN is completed. The 5 MW transferred from BMH to MLN is reversed, and BMH is supplied from the new MLN-BMH 66kV line. This project does not address the existing BLTS-BMH 66kV line approaching its N-1 rating, for the contingent loss of the new MLN-BMH 66 kV line. The estimated total direct capital and operating cost of this option is $25.3 million ($16.6 million present value in $2015), and the advancement of the 66 kV works at BMH means that the costs are higher than option one in present value terms. Operation and maintenance costs are estimated at 1% of the capital costs annually.

4.2 Classes of market benefits considered

In our assessment of the credible options, we had regard to the following classes of market benefits that may be delivered by the identified need:

- changes to voluntary load shedding;
- involuntary load shedding;
- changes in costs to other parties;
- difference in timing of distribution investment;
- changes in load transfer capacity;
- ability of embedded generators to take up load;
- additional option value; and
- changes in electrical energy losses.

The following sections define how these market benefits have been valued and if they have been considered as material in the assessment of credible options.

4.2.1 Changes to voluntary load shedding

As part of our non-network options report, we invited proponents to put forward demand management (load shedding) opportunities. As the majority of customers at both MLN and BMH consist of residential and smaller commercial/industrial customers, changes in voluntary load shedding would require a large take up by customers to defer the need for augmentation.

As we received no formal responses to our non-network options report, we have not considered any market benefits delivered from voluntary load shedding.

4.2.2 Changes in costs to other parties

MLN and BMH zone substations are supplied BLTS and Keilor Terminal Station (**KTS**) respectively.

The transfer of 5MW of load from BMH to MLN under credible options 1 and 3 will not adversely affect the transmission network supplying the zone substations. We consider, therefore, that no market benefits will arise from changes in costs to other parties.

4.2.3 Difference in timing of distribution investment

There are no major network augmentation projects planned at either MLN or BMH zone substations that would address the identified need within the period of this assessment. In addition, these credible options are not expected to materially alter the timing of any other future planned investments. As a result, we have not estimated any additional market benefits associated with changes in the timing of the distribution investment.

4.2.4 Option value

The estimation of option value benefits are captured in the scenario analysis section of this RIT-D assessment (refer to section 4.3). These are considered adequate to meet the Rules requirements of option value as a class of market benefit.

As a result, we do not propose to estimate any additional option value market benefits for this RIT-D assessment.

4.2.5 Changes in electrical losses

The increased capacity associated with the proposed credible options will lead to a reduction in electrical losses across all options.

The market benefits associated with a change in network losses have been quantified for the credible options by estimating the cost impact for each year of the modelling period. These additional figures were not seen as having a material impact on the assessment or timing of the credible options. As a result we have not included these benefits in the assessments.

4.3 Scenario and sensitivity assessment

In the assessment of credible network options, the Rules require RIT-D proponents to base the RIT-D assessment on a cost-benefit analysis that includes an assessment of reasonable scenarios of future supply and demand.[2]

The development of reasonable scenarios involves sensitivity analysis on key input values within the 'base case' scenario. Where a change to a parameter or value in the base case yields or is likely to yield a change in ranking of credible options, the RIT-D proponent should adopt additional reasonable scenarios that reflect variations in that parameter or value.

The following sections outline the details of the key base case parameters, and the basis of the variables used in the sensitivity analysis.

4.3.1 Demand forecasts

The upper bound forecast is based on a 5 per cent increase in average growth rates on the central value load forecasts. The lower bound forecast is based on a 5 per cent reduction in average growth on the central value load forecasts.

4.3.2 Discount rate

A real discount rate of 8.0 per cent was used in the central base case analysis for NPV calculations. For the purpose of sensitivity analysis, an lower and upper bound discount rate of 6.0 per cent and 9.0 per cent respectively have been applied.

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[2] NER, cl. 5.17.1.

4.3.3 Value of unserved energy

The MLN and BMH unserved energy values were calculated by applying the 2015 AEMO published Victorian VCR to the zone substation customer sectors. For the purpose of assessing sensitivity, a variation in costs resulting from a supply interruption have been calculated based on varying the calculated VCR within ±15 per cent.

4.3.4 Capital cost

The estimated capital cost of each credible option has been calculated using in-house estimation tools of both detailed and high level project scopes by our project estimating team. The cost level variation of these estimates is subject to a ±20 per cent range.

4.3.5 Summary of scenarios and sensitivity testing

A summary of the variables and the range of values used for our sensitivity testing are set out in Table 4.2.

Table 4.2 Variable ranges of the defined central 'base case' for sensitivity testing

Variable	Lower bound	Base case	Upper bound
Annual growth rate of forecast demand	-5.0 per cent of base case	MLN: 3.4 per cent BMH: 2.9 per cent BLTS-BMH: 3.2 per cent	+5.0 per cent of base case
Discount rate (real)	6.0 per cent	8.0 per cent	9.0 per cent
Value of Customer Reliability (**VCR**)	-15 per cent of base case	MLN: $34,546 per MWh BMH: $35,958 per MWh	+15 per cent of base case
Capital cost	-20 per cent of base case	MLN: $6.7M BMH: $6.5M BLTS-BMH: $7.4M	+20 per cent of base case

Based on the ranges set out in Table 4.2, we defined six scenarios that enable the sensitivity of the investment decision signal to be tested. These scenarios, set out in Table 4.3, contain plausible and mutually consistent combinations of key assumptions.

Table 4.3 Scenarios considered in the economic evaluation

Scenario	Demand growth	Discount rate	VCR	Capital cost
A	Upper bound	Upper bound	Upper bound	Upper bound
B	Upper bound	Upper bound	Lower bound	Upper bound
C	Central value	Upper bound	Upper bound	Lower bound
D	Central value	Lower bound	Lower bound	Upper bound

Scenario	Demand growth	Discount rate	VCR	Capital cost
E	Lower bound	Lower bound	Upper bound	Upper bound
F	Lower bound	Lower bound	Lower bound	Lower bound

4.4 Results of assessment

The results of our base case analysis, and the scenario testing are set out below.

4.4.1 Results of base case assessment

The total present value of costs for each credible network option consist of direct capital expenditure, operating expenditure, and expected unserved energy. These were evaluated for the base case scenario over a 19 year forecast period. The net market benefits, being the market benefits less costs, were calculated with reference to a do nothing option (which is defined as having a net market benefit of zero).

The results in Table 4.4 show that when assessed against the base case scenario, option three delivers the highest net market benefit of the options considered.

Table 4.4 Expected net economic benefit ($2015, million) of credible options under a base case scenario

Option	Description	Market benefit	Cost	Net benefit	Ranking
1	Install 3rd transformer at MLN and new 22kV feeder from BMH to MLN	998	15.5	982.9	2
2	Install new transformers at MLN and BMH, and augment sub-transmission line from BLTS to BMH	999	17.4	981.4	3
3	Install new transformer at MLN and new 66kV line operating at 22kV from BMH to MLN	1001	16.6	984.7	1

The net market benefit of option three is higher than both options one and two for the following reasons:

- Option three has the second highest overall total project costs (combined capital and operational) of the three options presented in the report. This is due to the deferral of major capital costs associated with the installation of the new transformer at BMH zone substation and augmentation of the BLTS-BMH sub transmission line compared with option two.
- Option three reduces a higher initial amount of load at risk with a lower capital expenditure when compared to option two.
- Option three has a marginally higher net economic benefit when compared to option one due to the construction of a new 66kV sub transmission line between MLN to BMH. The new line will become the main 66kV supply to BMH zone substation with the existing BLTS-BMH 66kV line becoming the secondary N-1 contingency supply.

The additional network benefits of option three, when compared to the other options, includes the following:

- The increase in transformer capacity at MLN will improve the station N-1 rating and will bring the station to its ultimate design capacity.
- Increase in distribution network tie capacity between MLN and BMH zone substations, allowing for greater load transfers during planned and unplanned outages.
- The new MLN 22kV feeder (partially built at 66kV) will improve the distribution network capacity and allow for future growth and development in the Melton north area.
- The future development plan for the sub transmission network is to connect the existing BLTS-BMH 66kV line into the new Deer Park Terminal Station (**DPTS**) and create a DPTS-MLN-BMH 66kV loop. The economic timing of this project will depend on the N-1 contingency energy at risk of the DPTS-BMH line.

4.4.2 Results of scenario and sensitivity assessment

The results in Table 4.5 show the result of the NPV analysis for the alternative scenarios defined in Table 4.3. The results of the base case scenario are also shown for comparison. Option three delivers the highest net market benefit of the options considered under each scenario.

Table 4.5 Scenarios considered in the economic evaluation

Scenario	Option 1	Option 2	Option 3
Base case	982.9	981.4	984.7
Scenario A	837.2	837.0	842.0
Scenario B	778.2	777.2	780.6
Scenario C	787.2	786.5	789.1
Scenario D	1224.1	1222.9	1225.4
Scenario E	1227.3	1225.6	1227.9
Scenario F	1237.1	1235.9	1237.4

5 Proposed preferred option

This section sets out the details associated with the proposed preferred option, including the technical characteristics, construction timetable and indicative costs.

5.1 Preferred option

On the basis of the analysis presented in this report, and subject to any further information provided by interested parties in response to this paper, our preferred network option to address the overloaded MLN and BMH zone substations, and the BLTS-BMH 66kV line, is to install a third transformer at MLN and a new feeder MLN to transfer 5MW of load off BMH. The analysis set out in section four clearly demonstrates that this option (option three) maximises the net market benefits to all those who produce, consume and transport electricity in the National Electricity Market (**NEM**).

5.2 Technical characteristics

The technical characteristics of the preferred option are as follows:

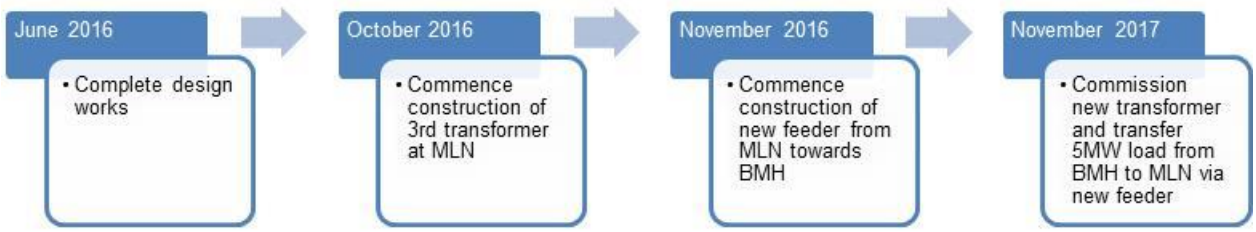
- install a third transformer (25/33 MVA), with a fourth 66kV circuit breaker and a third 22 kV indoor bus at Melton zone substation, at an estimated cost of $4.9 million;
- install a new 22 kV distribution feeder (partially built using 66kV construction) and tie into the existing MLN network, at an estimated cost of $1.8 million; and
- transfer 5MW of existing BMH customers onto the new MLN feeder to relieve the load at risk at BMH zone substation and BLTS-BMH 66kV line.

The total estimated direct capital cost of the project is $6.7 million.

5.3 Construction timetable

The following flow chart depicts the estimated dates for the milestones of design; construction and commissioning of the preferred option.

Figure 5.1 Construction timetable



5.4 Satisfaction of RIT-D

We consider that the proposed preferred option satisfies the RIT-D. This statement is made based on the detailed analysis set out in this report. The proposed preferred option is the credible option that has the highest net economic benefit.

6 Lodging a submission

We invite written submissions on the network solution identified in this report from any interested parties. Our aim is to develop the distribution network in a manner that maximises net economic benefits to all those who produce, consume and transport electricity in the NEM. To this end, additional information is included in attachment A for proponents of non-network solutions who may wish to lodge proposals for a non-network alternative to the identified network solution.

Proponents of non-network solutions should make initial contact as soon as possible, to ensure that sufficient time is available to fully assess the feasibility of their potential solution. It should be noted, however, that parts of the network experience volatile load growth. This is usually a direct consequence of economic and demographic factors that are difficult to foresee and model. It is essential, therefore, that alternatives to the proposed network solution are presented by proponents in sufficient time to allow for their thorough evaluation, planning and implementation.

6.1 Where to lodge submissions or direct queries

Submissions can be provided electronically to the email address provided below:

- ritdenquiries@powercor.com.au

Alternatively, submissions may be lodged by mail to the following address:

- Locked Bag 14090 Melbourne Vic 8001, attention to Andrew Dinning, Network Planning and Development - Central Planning Group, Level 6.

All submissions will be published on our website. If you do not want your submission to be made publicly available please state this at the time of lodgement.

All submissions are due on or before 16:00 on 18th March 2016.

6.2 Next steps

Following our review of any submissions made, the chosen option to address the identified will be included as part of the final project assessment report. This report will present the final stage of the RIT-D process.

We intend to complete our review of submissions and selection of the chosen option by May 2016.

7 Checklist of regulatory compliance

Table 7.1 provides a cross reference between this report and the relevant sections of the Rules.

Table 7.1 Regulatory compliance checklist

Reference	Requirement	Section
5.17.4(j)(1)	Description of the identified need for the investment	3
5.17.4(j)(2)	The assumptions used in identifying the identified need (including, in the case of proposed reliability corrective action, reasons that the RIT-D proponent considers reliability corrective action is necessary)	3.2
5.17.4(j)(3)	If applicable, a summary of, and commentary on, the submissions on the non-network options report	4.1
5.17.4(j)(4)	Description of each credible option assessed	4.1
5.17.4(j)(5)	Where a Distribution Network Service Provider has quantified market benefits in accordance with clause 5.17.1(d), a quantification of each applicable market benefit for each credible option	4.2–4.4
5.17.4(j)(6)	A quantification of each applicable cost for each credible option, including a breakdown of operating and capital expenditure	4.2–4.4
5.17.4(j)(7)	A detailed description of the methodologies used in quantifying each class of cost and market benefit	4.2–4.4
5.17.4(j)(8)	Where relevant, the reasons why the RIT-D proponent has determined that a class or classes of market benefits or costs do not apply to a credible option	4.2
5.17.4(j)(9)	The results of a net present value analysis of each credible option and accompanying explanatory statements regarding the results	4.4
5.17.4(j)(10)	The identification of the proposed preferred option	5
5.17.4(j)(11)	For the proposed preferred option, the RIT-D proponent must provide: • details of the technical characteristics; • the estimated construction timetable and commissioning date (where relevant); • the indicative capital and operating cost (where relevant); • a statement and accompanying detailed analysis that the proposed preferred option satisfies the regulatory investment test for distribution; and • if the proposed preferred option is for reliability corrective action and that option has a proponent, the name of the proponent	5
5.17.4(j)(12)	Contact details for a suitably qualified staff member of the RIT-D proponent to whom queries on the draft report may be directed	6

A Additional information for non-network solutions

Tables A.1 to A.3 provide data on energy and hours at risk for forecast demand (excluding any planned augmentation or operational response such as load transfers to mitigate the impact of an outage).

Table A.1 MLN: magnitude and impact of loss of load

Year	50th percentile demand forecast (MVA)		10th percentile demand forecast (MVA)		10th percentile annual energy at risk (N-1 rating)		10th percentile annual energy at risk (N-1 rating)		50th percentile annual energy at risk (N rating)		10th percentile annual energy at risk (N rating)	
	Summer	Winter	Summer	Winter	MWh	Hrs	MWh	Hrs	MWh	Hrs	MWh	Hrs
2015	59.6	44.5	68.1	47.2	1,041	153	2,537	316	0	0	0	0
2016	64.2	42.3	73.4	44.9	1,642	212	3,900	414	0	0	0	0
2017	66.8	43.0	76.4	45.7	2,085	255	4,881	523	0	0	0	0
2018	69.3	43.5	79.3	46.1	2,604	306	6,072	662	0	0	0	0
2019	71.7	44.1	82.0	46.8	3,157	363	7,403	836	0	0	2	2
2020	74.8	44.9	85.6	47.7	4,023	459	9,550	1,106	0	0	22	9
2021	77.2	45.7	88.3	48.5	4,809	555	11,522	1,351	0	0	53	16
2022	78.4	45.4	89.6	48.2	5,246	607	12,560	1,454	0	0	75	20
2023	81.9	46.6	93.6	49.4	6,811	824	16,302	1,882	2	2	172	33
2024	85.7	48.0	97.9	51.0	8,939	1,123	21,025	2,317	23	9	329	50
2025	89.6	49.0	102.5	52.1	11,738	1,489	26,596	2,718	76	20	554	66
2026	93.8	50.2	107.2	53.3	15,366	1,930	33,062	3,077	177	33	861	88
2027	97.4	50.7	111.4	53.8	18,934	2,264	38,849	3,316	307	48	1,194	110
2028	101.2	51.2	115.6	54.3	23,026	2,587	45,109	3,526	485	62	1,603	132
2029	105.1	51.7	120.1	54.9	27,632	2,878	51,811	3,721	712	78	2,097	156
2030	109.1	52.2	124.7	55.4	32,706	3,127	58,965	3,932	1,005	99	2,691	184
2031	113.3	52.7	129.5	56.0	38,218	3,351	66,577	4,156	1,372	119	3,411	220
2032	117.7	53.2	134.5	56.5	44,152	3,543	74,671	4,372	1,819	143	4,282	264
2033	122.2	53.8	139.6	57.1	50,488	3,746	83,226	4,498	2,357	168	5,338	316

Table A.2 BMH: magnitude and impact of loss of load

Year	50th percentile demand forecast (MVA)		10th percentile demand forecast (MVA)		10th percentile annual energy at risk (N-1 rating)		10th percentile annual energy at risk (N-1 rating)		50th percentile annual energy at risk (N rating)		10th percentile annual energy at risk (N rating)	
	Summer	Winter	Summer	Winter	MWh	Hrs	MWh	Hrs	MWh	Hrs	MWh	Hrs
2015	28.5	25.3	34.2	26.6	891	450	2,814	1,032	0	0	0	0
2016	27.4	26.3	33.0	27.6	1,069	542	2,917	1,065	0	0	0	0
2017	28.5	27.3	34.4	28.7	1,581	735	4,110	1,461	0	0	0	0
2018	29.3	27.9	35.3	29.3	1,967	874	5,025	1,762	0	0	0	0
2019	30.6	29.1	36.9	30.5	2,923	1,216	7,237	2,385	0	0	0	0
2020	32.1	30.2	38.7	31.8	4,204	1,612	10,150	3,094	0	0	0	1
2021	33.6	31.6	40.5	33.2	6,053	2,119	14,045	3,840	0	0	5	5
2022	34.6	32.4	41.8	34.1	7,397	2,465	16,863	4,292	0	0	14	9
2023	36.3	33.9	43.8	35.6	10,268	3,130	22,329	5,007	0	0	44	21
2024	38.1	35.5	46.0	37.3	13,961	3,860	28,825	5,653	0	0	97	33
2025	39.9	36.9	48.2	38.8	17,918	4,523	35,369	6,164	3	3	176	50
2026	41.9	38.6	50.5	40.6	23,056	5,165	43,271	6,682	15	10	293	71
2027	43.3	40.1	52.3	42.2	27,769	5,650	50,172	7,061	35	18	415	98
2028	44.9	41.7	54.1	43.8	32,965	6,103	57,561	7,395	70	31	591	144
2029	46.4	43.3	56.0	45.6	38,621	6,511	65,402	7,661	134	59	859	218
2030	48.1	45.0	58.0	47.4	44,699	6,855	73,650	7,857	261	114	1,264	317
2031	49.8	46.8	60.0	49.2	51,156	7,147	82,268	7,950	491	189	1,843	442
2032	51.5	48.7	62.1	51.2	57,963	7,376	91,192	7,953	857	282	2,645	599
2033	53.3	50.6	64.3	53.2	65,075	7,541	100,330	7,839	1,395	396	3,735	807

Table A.3 BLTS-BMH: magnitude and impact of loss of load (at BMH end)

Year	50th percentile demand forecast (MVA)		10th percentile demand forecast (MVA)		10th percentile annual energy at risk (N-1 rating)		10th percentile annual energy at risk (N-1 rating)		50th percentile annual energy at risk (N rating)		10th percentile annual energy at risk (N rating)	
	Summer	Winter	Summer	Winter	MWh	Hrs	MWh	Hrs	MWh	Hrs	MWh	Hrs
2015	35.6	29.3	39.9	33.4	82	31	375	142	9	6	75	27
2016	33.6	29.9	37.6	34.1	43	25	367	161	1	1	30	15
2017	36.2	31.7	40.5	36.1	132	69	807	278	13	8	91	31
2018	37.9	32.6	42.4	37.2	223	102	1,134	348	34	17	154	45
2019	39.3	34.7	44.0	39.6	482	196	1,995	526	61	24	232	69
2020	42.5	36.7	47.6	41.8	979	321	3,304	763	156	44	507	144
2021	43.9	38.1	49.2	43.5	1,435	422	4,447	974	219	59	743	208
2022	45.4	39.6	50.9	45.2	2,036	543	5,872	1,200	307	81	1,082	287
2023	47.0	41.2	52.6	46.9	2,818	692	7,608	1,448	441	123	1,553	386
2024	48.5	42.8	54.4	48.8	3,820	884	9,673	1,703	651	181	2,185	504
2025	50.2	44.5	56.2	50.7	5,079	1,101	12,066	1,952	963	253	3,019	652
2026	51.9	46.2	58.1	52.7	6,622	1,344	14,788	2,197	1,405	342	4,116	844
2027	53.6	48.0	60.1	54.8	8,465	1,599	17,774	2,400	2,008	452	5,570	1,103
2028	55.5	49.9	62.1	56.9	10,610	1,849	20,932	2,523	2,812	586	7,478	1,431
2029	57.3	51.9	64.2	59.1	13,051	2,098	24,220	2,609	3,871	760	9,917	1,807
2030	59.3	53.9	66.4	61.4	15,744	2,331	27,558	2,654	5,272	987	12,975	2,234
2031	61.3	56.0	68.6	63.8	18,587	2,476	30,885	2,608	7,129	1,290	16,705	2,716
2032	63.3	58.2	70.9	66.3	21,509	2,577	34,171	2,554	9,527	1,643	21,154	3,211
2033	65.5	60.5	73.3	68.9	24,445	2,646	37,367	2,446	12,556	2,053	26,374	3,741