26/04/2016

Petition

Official objection to the proposed overhead 132kV powerline. Macon Road, Lorraine Manor.

18 houses affected.

Please note that the residents along Macon road are objecting to the powerline being overhead. We insist that it be underground.

The only reason why it is argued to be overhead, is due to costs. They cant afford an underground cable, but the residents must absorb the loss in value to their property, sacrifice and loose the natural appearance and tranquillity of the area, live with the risks and dangers associated with such wires in such close proximity to our homes, the noise and pure ugliness.

Macon on Bergues – Joseph (Rudi) van Schalkwyk jvanschalkwyk@hatch.co.za

279 Macon Road – Michelle mdupreez@elliespe.co.za

281 Macon Road – Leon Minne leonminne@mweb.co.za (LCMINNE)

283 Macon Road-

285 Macon Road- cecil@falcontiling.co.za

287 Macon Road- Mandy Elliot mandy.elliott@imp.co.za

289 Macon Road- Suzette sclegg@oldmutual.com

291 Macon on Blanc

291 Macon on Blanc MRS THERÉSÉ SWART therese.swart@za.pwc.com

293 Macon on Blanc- M/S Lorna Peters 0832109350

295 Macon Road- Eugene van Wyngaardt vanwyng@vwsa.co.za

297 Macon Road – Helen HGray. 0826793304

299 Macon Road- 0847630698

301 Macon Road- Mark Reid reid01@vwsa.co.za

303 Macon Road- Karel Steyn karel.steyn@gmail.com

305 Macon Road- Chris Gagiano chrisgagiano@gmail.com

307 Macon Road Petra Alberts flipa@gmail.com petra@goldlaw.co.za

309 Macon Road on Revaud@webmail.co.za

401 Macon Road on

Marais, Wanda

From:	van Wyngaardt, Eugene <vanwyng@vwsa.co.za>
Sent:	10 May 2016 10:10 AM
To:	Marais, Wanda; Ward8 NMMM; Safety & Security Cllr - Rautenbach
Cc:	mdupreez@elliespe.co.za; cecil@falcon.co.za; mandy.elliott@imp.co.za; sclegg@oldmutual.com; karel.steyn@gmail.com; chrisgagiano@gmail.com; leonminnie@mweb.co.za; Reid, Mark; jvanschalkwyk@hatch.co.za; Van Wyngaardt, Charmaine (CVanWyngaardt@hatch.co.za); therese.swart@za.pwc.com; flipa@gmail.com; petra@goldlaw.co.za; renaud@webmail.co.za
Subject:	RE: "Proposed 132kV Powerline, Macon Road, Lorraine"
Attachments:	ATT00001.txt; ATT00002.htm

Good Morning Wanda,

In response to the below. Thank you for the registration of the residents.

I can confirm that, 293 Macon – Lorna Peters, 297 Macon – Helen Gray and 299 Macon – Mrs J Patton, DO NOT HAVE e-mail.

Furthermore, in response to the RESPONSE in the “Executive Summary” with regards to laying the cable underground along Macon road. The response stated “NOT FINANCIALLY FEASABLE”.

Are they aware that currently a 3m deep trench is available as they are laying stromwater pipes. Surely with the correct planning the same trench can be utilized for the cables ???

Regards

Eugene van Wyngaardt (295 Macon – 041 994 4373)

From: Marais, Wanda [mailto:WMarais@srk.co.za]
Sent: 05 May 2016 11:52 AM
To: van Wyngaardt, Eugene; Ward8 NMMM; Safety & Security Cllr - Rautenbach
Cc: mdupreez@elliespe.co.za; cecil@falcon.co.za; mandy.elliott@imp.co.za; sclegg@oldmutual.com; karel.steyn@gmail.com; chrisgagiano@gmail.com; leonminnie@mweb.co.za; Reid, Mark; jvanschalkwyk@hatch.co.za; Van Wyngaardt, Charmaine (CVanWyngaardt@hatch.co.za); therese.swart@za.pwc.com; flipa@gmail.com; petra@goldlaw.co.za; renaud@webmail.co.za
Subject: RE: "Proposed 132kV Powerline, Macon Road, Lorraine"

Dear Eugene,

Marais, Wanda

From: Warren Parker (Director) <wp@jgs.co.za>
Sent: 17 May 2016 09:21 AM
To: Marais, Wanda
Subject: Proposed 132 kV Powerline, Walmer, Port Elizaberth

Importance: High

Joubert Galpin Searle

Astute lawyers with business acumen
Commercial • Conveyancing • Labour • Litigation • Recoveries

Dear Wanda,

As you know I represent Stylestar Porperties 191 (Pty) Ltd.

I have also been approached by Capeco to assist them in submitting comment to the draft assessment report in relation to the proposed powerline.

These comments are required by 18 May 2016.

We have previously suggested (by way of email dated 11 May 2016) that the information furnished to us by you in relation to the relative cost of constructing the powerline underground as opposed to above ground, be circulated to all interest parties and that the date for the submission of comments be extended.

We have also requested the paperwork which supports the costs provided to us.

As the comments submission deadline is tomorrow, we urgently request that you confirm that the deadline be extended.

We are still not in possession of the information requested from you and which directly impacts on the comments our clients intend to submit.

Kind regards

WARREN PARKER
Director

t +27 41 396 9234 **f** +27 41 373 3588 **c** + 27 78 456 7859
173 Cape Road, Mill Park, Port Elizabeth PO Box 59, Port Elizabeth, 6000
Docex 12, Port Elizabeth

Click here to view our Terms & Conditions

Marais, Wanda

From:	John Baeyens <john.baeyens@gmail.com> on behalf of John Baeyens <john@vinlanda.com.br>
Sent:	18 May 2016 08:49 AM
To:	Marais, Wanda
Cc:	Marc Crocker; Warren Parker
Subject:	Proposed 132kV Powerline: #1 precise location, impact
Importance:	High

Dear Wanda,

It is unclear to us where the Powerline will run.
There is a very vague drawing iover a satelite picture.

However, the proposed power line (underground, or above ground; see respective distances) appears to run in/over a riverbed, with 100 year bloodline, etc... We would need oprecise drawings where the powerlines would be running over (or under if underground) and also the exact locations of the infrastructure on the ground (pilots in concrete,...) as to assess the impact of all infrasrtucture in and above the ground.

Can you provide this?

Best regards,

John Baeyens
Capeco

Marais, Wanda

From: John Baeyens <john@capeco.co.za>
Sent: 18 May 2016 08:52 AM
To: Marais, Wanda
Cc: Marc Crocker; Warren Parker
Subject: Proposed 132kV Powerline: #2 impact land

Importance: High

Dear Wanda,

It is completely unspecified how and on what grounds these pillars would be placed on our land, how much land would be bought, at which conditions.
Please take into considerations the ROD on our land South of the river and the impact on even/units (people cannot and do not want to liver directly under the lines0>

We would need this detailed analysis.

Best regards,

John Baeyens
Capeco

Marais, Wanda

From: John Baeyens <john@capeco.co.za>
Sent: 18 May 2016 08:57 AM
To: Marais, Wanda
Cc: Marc Crocker; Warren Parker
Subject: Proposed 132kV Powerline: #3 detailed cost assesment underground and above ground

Importance: High

Dear Wanda,

The report DBAR claims that the option to put the Powerline underground is not an option because of cost.
There is absolute no further detailing.

Such a claimm needs detailed study and discussion.

- What is the extra cost for (partly) putting the Powerline under the ground
- Compared to the health of our feature residents and massive loss of revenue/land of Capeco (see comment #2) because of people not buyuing units because of health concerns and aesthetic impact

During the past weeks our lawyers have tried fruitless to obtain such cost breakdown (detailed itemised budget aboveground versus underground). Not just a number thrown in the air, but a detailed cost breakdown from the involved engineers. We have been requesting a meeting with the engineers and yourself to discuss this option, can this please be entertained as soon as possible?

Best regards,

John Baeyens
Capeco

Marais, Wanda

From: John Baeyens <john@capeco.co.za>
Sent: 18 May 2016 09:01 AM
To: Marais, Wanda
Cc: Marc Crocker; Warren Parker
Subject: Proposed 132kV Powerline: #4 explanation as to needs and

Importance: High

Dear Wanda,

We could not read in the DBAR who is the party driving the application: is it Eskom orthe municipality? Who is the legal respresentative of the applicant (director, government official?)

What are the needs (fro,m where to where) which these lines will cater and what causes the extra demand for these lines to be put in place? There are alredy powerlines running alomside William Moffet on one side and Dijon on the other side of Circular Drive. Why can these lines not be upgraded to cater for the extra capacity? As such avoiding the unaccepteable proposal to run 132kV powerlines above a desenily populated (and to be populated) neighbourhood.

We would need to understand exactly in a detailed study how these options where studied, what all the alternative options are and.

Can you please send us this detailed analysis?

John Baeyens
Capeco

Marais, Wanda

From: John Baeyens <john@capeco.co.za>
Sent: 18 May 2016 12:12 PM
To: Marais, Wanda
Cc: nm@jgs.co.za; Warren Parker; Marc Crocker
Subject: Fwd: Proposed Alignment Coordinates
Attachments: 18 KIR2-0022 Annexure G.pdf

Importance: High

Thank you Narene,

Wanda,

We are unable to asses the impact with this.
We need to see drawings of the actual infrasrtcuture (footings, concrete,…) on the precise locations on a detailed map (the satelite pictures don't allow us to asses impact).

Read: we need actual detailed architectural drawings of ANY infrastructure (pillars, concrete foundations, access roads, fences,…) that would be constructed.

Sincerely,

John Baeyens

Begin forwarded message:

From: "Narene Menges [nm@jgs.co.za]" <nm@jgs.co.za>
Subject: Proposed Alignment Coordinates
Date: 18 May 2016 at 09:33:01 GMT+2
To: "marc@capeco.co.za" <marc@capeco.co.za>, "john@capeco.co.za" <john@capeco.co.za>

Joubert Galpin Searle
Astute lawyers with business acumen
Commercial • Conveyancing • Labour • Litigation • Recoveries

Dear Gentlemen

Attached, please find Proposed Alignment Coordinates, as attached as Annexure G to the Pre-Application Draft Basic Assessment Report.

Kind regards

NARENE MENGES
Secretary to WARREN PARKER

t +27 41 396 9234 **f** +27 41 373 3588 Docex 12, Port Elizabeth
173 Cape Road, Mill Park, Port Elizabeth PO Box 59, Port Elizabeth, 6000

Appendix G: Proposed Alignment Coordinates

Alternative S1 (Preferred Alternative)

Point	Latitude (S):		Longitude (E):	
A	33°	58'35.57"	25°	31'31.05"
B	33°	58'40.25"	25°	31'47.56"
C	33°	58'42.22"	25°	31'51.69"
D	33°	58'40.47"	25°	31'55.80"
E	33°	58'41.00"	25°	31'59.58"
F	33°	58'31.43"	25°	32'18.00"
H	33°	58'32.35"	25°	32'39.01"
I	33°	58'35.09"	25°	32'46.28"
J	33°	58'35.27"	25°	32'50.40"
K	33°	58'31.89"	25°	32'58.34"
L	33°	58'32.58"	25°	33'16.19"

Alternative S2

Point	Latitude (S):		Longitude (E):	
A	33°	58'35.57"	25°	31'31.05"
B	33°	58'40.25"	25°	31'47.56"
C	33°	58'42.22"	25°	31'51.69"
D	33°	58'40.47	25°	31'55.80"
E1	33°	58'	25°	32'3.37"
G	33°	58'	25°	32'21.66"
H	33°	58'	25°	32'39.01"
I	33°	58'	25°	32'46.28"
J	33°	58'	25°	32'50.40"
K	33°	58'	25°	32'58.34"
L	33°	58'	25°	33'16.19"

Marais, Wanda

From:	Karel Steyn <karelsteyn@gmail.com>
Sent:	17 May 2016 05:43 PM
To:	Marais, Wanda
Subject:	Re: Reminder: Pre-Application DBAR Proposed 132kV Powerline, Walmer, Port Elizabeth

Dear Wanda,

Please remove my name from the mailing list. I live in Potchefstroom and I think you have the from email address.

Regards

Karel Steyn

On 17 May 2016 13:31, "Marais, Wanda" <WMarais@srk.co.za> wrote:

Dear Authorities, Stakeholders and IAPs,

Reminder: Pre-Application DBAR Proposed 132kV Powerline, Walmer, Port Elizabeth

This serves as a reminder that the deadline for comment as per the Pre-Application Draft Basic Assessment Report (DBAR) for the proposed 132kV Powerline, Walmer, will expire at **12h00** on **18 May 2016.**

You are kindly requested to forward your comments to us timeously to ensure that they will be included in, and addressed in the Post-Application Basic Assessment Report to be released in due course.

Kind Regards,

Wanda Marais B Proc

Public Participation Practitioner

srk consulting

SRK Consulting (South Africa) (Pty) Ltd

Marais, Wanda

From:	Rudi van Schalkwyk <rudi_vans@hotmail.com>
Sent:	18 May 2016 10:29 AM
To:	Marais, Wanda
Subject:	Re: Reminder: Pre-Application DBAR Proposed 132kV Powerline, Walmer, Port Elizabeth

Good morning, Wanda.

Since all other concerns were seemingly brushed off, I would like to raise my main concern.

What are the proposed mitigation measures for the depreciation in value of my property?
There will be a definite drop in value with the unsightly power line across the road.

Kind regards
Rudi

Get Outlook for Android

On Tue, May 17, 2016 at 4:31 AM -0700, "Marais, Wanda" <WMarais@srk.co.za> wrote:

Dear Authorities, Stakeholders and IAPs,

Reminder: Pre-Application DBAR Proposed 132kV Powerline, Walmer, Port Elizabeth

This serves as a reminder that the deadline for comment as per the Pre-Application Draft Basic Assessment Report (DBAR) for the proposed 132kV Powerline, Walmer, will expire at **12h00** on **18 May 2016.**

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Kind Regards,

Wanda Marais B Proc
Public Participation Practitioner

srk consulting

SRK Consulting (South Africa) (Pty) Ltd

Ground Floor, Bay Suites, 1a Humewood Rd, Humerail, Port Elizabeth, 6001
P O Box 21842, Port Elizabeth, 6000
Tel: +27-(0)41-509-4809; **Fax**: +27-(0)41-509-4850
Email: wmarais@srk.co.za

www.srk.co.za

Joubert Galpin Searle
Port Elizabeth

MRS WANDA MARAIS
SRK Consulting (South Africa) (Pty) Ltd
e-mail: wmarais@srk.co.za

Our Ref: W PARKER/nm/KIR2/0022
Your Ref:

18 May 2016

Dear Madam

PROPOSED 132 KV POWERLINE, WALMER

1. We represent:

   1.1 Stylestar Properties 191 (Pty) Ltd (the owner of Erf 4033, Fairview) and Kirland Investments (Pty) Ltd, who jointly intend to develop Erf 4033, Fairview as a Private Hospital; and

   1.2 Capeco Development (Pty) Ltd, the owner of the remainder of Erf 1226, Fairview, who intends to develop the remainder of Erf 1226, Fairview, for *inter alia*, residential housing.

<u>Fairness of public participation process</u>

2. Our clients are listed as interested and/or affected parties.

3. On Friday, 15 April 2016 we obtained a copy of the Pre-Application Draft BAR (the "Draft Report") from you.

4. One of the comments raised by our clients in relation to the proposed powerline was whether any consideration had been given to placing the powerline underground, as opposed to above the ground.

5. The response in the Draft Report to the above comment was that "*The option of underground cables for additional section of the route is not financially feasible*".

6. On Tuesday, 19 April 2016 (within 1 business day of having received the Draft Report), we addressed queries to you in relation to the respective costs of placing the powerline underground as opposed to above the ground. A copy of our e-mail is attached marked "A".

7. You acknowledged receipt of our e-mail query 9 days later on Thursday, 28 April 2016 (a copy of your e-mail is attached marked "B"), and we only received your response to our client's queries on Thursday, 5 May 2016 (a copy of your e-mail is attached marked "C").

8. On Wednesday, 11 May 2016 (3 business days after receipt of your e-mail dated 5 May 2016), we addressed an e-mail to you indicating that the information in relation to the cost of placing the powerlines underground as opposed to above the ground was highly relevant to assessing whether the granting of environmental authorization for the placing of powerlines above the ground, was the only reasonable and feasible alternative.

9. We, in addition, contended that it would be prudent to also extend the date by which comments were to be submitted so that all interested and affected parties were afforded an equal amount of time to submit comments in relation to Draft Report.

10. No response was forthcoming in relation to our queries dated 11 May 2016 necessitating us having to address a further e-mail to yourselves on 17 May 2016 (a copy of our e-mail dated 17 May 2016 is attach marked "D").

11. Within 2 hours of receiving our communication, you advised that it was not possible to extend the date by which comments were to be submitted. No explanation was advanced why this response was not communicated to us shortly after receipt by you of our e-mail dated 11 May 2016.

12. Our clients submit that:

    12.1 The delay in furnishing highly relevant information in relation to the relative costs of placing the powerlines underground as opposed to above the ground; and

    12.2 The Delay in responding to our clients legitimate and reasonable requests for extensions of time within which to submit comments,

    were directed at frustrating our clients entitlement to submit full and comprehensive comments to the Draft Report.

13. All of our clients' right remain strictly reserved to challenge the fairness of the public participation process on this ground alone.

Underground option feasible

14. You have confirmed that the cost of constructing a powerline above the ground is in the order of R550 000.00 per km as opposed to the cost of placing the line underground of R1 900 000.00, representing an additional cost of R1 450 000.00 per km.

15. The Draft Report confirms that the length of the proposed powerline is approximately 2.8 km long.

16. The additional cost for placing the powerline underground is accordingly R4 060 000.00.

17. In response to the query whether any effort had been made to source additional funding in respect to laying the line underground, your response was "*The budget in the past financial years have been significantly reduced due to financial constraints facing the entire institution. Getting additional funding for this exercise is not possible as the overhead line is the suitable line both practically and financially.*"

18. Our clients submit that the stated impacts of the placement of the proposed powerline above the ground can be entirely mitigated by placing the powerline underground.

19. The response in relation to funding the additional cost of placing the powerline underground is misleading.

20. The Nelson Mandela Bay Municipality ("NMBM"), makes application to the National Energy Regulator ("NERSA"), from time to time, for the determination of an electricity tariff.

21. The application for the determination of such a tariff, includes, *inter alia*:

    21.1 The actual cost of the acquisition of electricity from Eskom;

    21.2 The capital cost of developing electrical distribution infrastructure;

    21.3 The ongoing cost of maintaining electrical distribution cost.

    [Please see NERSA Guidelines on Minimum Information Requirements for Electricity Tariff Applications and NERSA Cost of Supply Framework Marked "E" and "F"]

22. The tariff imposed by the NMBM accordingly makes provision for the recovery of capital expenditure incurred by the NMBM.

23. Any additional capital cost incurred by the placing of the powerlines underground would accordingly be recoverable by a electricity tariff determined by NERSA taking into consideration the actual capital expenditure incurred by the NMBM in this regard.

24. It is accordingly incorrect and misleading to suggest that it is not economically feasible to construct the powerline underground.

25. In addition to the above, the NMBM has confirmed that the purpose of constructing the proposed powerline, is to supplement the supply of electricity, for, *inter alia*, commercial developments along William Moffett Expressway. No consideration appears to have been given to imposing a levy on the approval to such developments to fund the cost of the improvements to the electrical distribution network of the NMBM, much akin to the imposition of site development levies.

26. Accordingly, our clients do not accept that the placement of the proposed powerline underground is not economically feasible. It is economically feasible, and the entire cost is recoverable through the NMBM electrical tariff determination process by NERSA.

<u>1:100 Year flood line</u>

27. It is noted that the coordinates of the proposed placement of the powerline bases have been included in the Draft Report.

28. No indication is given as to whether the placement of these powerline bases occurs within the 1:100 year flood line for the water course along and in which the proposed powerline shall travel.

29. In our clients' submission, this is a serious shortcoming in the Draft Report which is required to be rectified prior to the submission of the report to DEDEAT.

Reservation of rights

30. For the reasons stated above, our clients have not been is a position to submit technical comments in relation to the Draft Report. Our clients do however persist with the comments previously submitted by them.

31. It has been confirmed by you that our clients will be afforded an additional opportunity to comment on the further report compiled with reference to the comments received, prior to the submission of such report to DEDEAT.

32. Our clients intend to submit technical comments, and would appreciate a copy of the further report being provided to them immediately once it has been finalised, to enable them to do so.

Yours faithfully

JOUBERT GALPIN SEARLE

WARREN PARKER

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Encl.

Joubert Galpin Searle

Port Elizabeth

MRS WANDA MARAIS
SRK Consulting (South Africa) (Pty) Ltd
e-mail: wmarais@srk.co.za

Our Ref: W PARKER/nm/KIR2/0022
Your Ref:

18 May 2016

Dear Madam

PROPOSED 132 KV POWERLINE, WALMER

1. We represent:

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Commercial • Conveyancing • Estates • Labour • Litigation • Recoveries

Port Elizabeth — PO Box 59, Port Elizabeth, 6000 — 173 Cape Road, Mill Park, Port Elizabeth, 6001, South Africa — DOCEX 12 Port Elizabeth — t +27 41 396 9234 — f +27 41 373 3588 — wp@jgs.co.za — www.jgs.co.za

Grahamstown — PO Box 50, Grahamstown, 6140 — 22 Somerset Street, Grahamstown, 6139, South Africa — DOCEX 20 Grahamstown — t +27 46 622 2692 — f +27 86 206 5517 — grahamstown@jgs.co.za

7. You acknowledged receipt of our e-mail query 9 days later on Thursday, 28 April 2016 (a copy of your e-mail is attached marked "B"), and we only received your response to our client's queries on Thursday, 5 May 2016 (a copy of your e-mail is attached marked "C").

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    21.2 The capital cost of developing electrical distribution infrastructure;

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    [Please see NERSA Guidelines on Minimum Information Requirements for Electricity Tariff Applications and NERSA Cost of Supply Framework Marked "E" and "F"]

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Yours faithfully

JOUBERT GALPIN SEARLE

WARREN PARKER

For terms and conditions of service see www.jgs.co.za/terms

Encl.

From: Warren Parker (Director) [mailto:wp@jgs.co.za]
Sent: 19 April 2016 11:32 AM
To: Marais, Wanda
Subject: Proposed 132 kV Powerline, Walmer, Port Elizabeth
Importance: High

"A"

Joubert Galpin Searle

Dear Wanda,

I confirm my representation of Stylestar Properties 191 (Pty) Ltd.

I have received your Executive Summary and have also downloaded the draft report and annexures from your website.

The response to the suggestion by objectors that the electricity line be placed underground is "*The option of installing an underground cable for the entire route was eliminated during the design phase of the proposed development due to costs*".

Could you please provide us with some clarity in this regard as it would assist us in formulating our clients comments to the draft assessment report:

1. When were the relative costs compared?
2. Have the costs been revisited since then?
3. What are the exact costs of constructing an overhead line versus an underground line?
4. Has any effort been made to source additional funding in respective of laying the line underground?
5. How could the alternative of laying the cable underground be eliminated prior to receiving comments on the proposal?

I look forward to hearing from you in this regard.

Kind regards

WARREN PARKER
Director

t +27 41 396 9234 **f** +27 41 373 3588 **c** + 27 78 456 7859
173 Cape Road, Mill Park, Port Elizabeth · PO Box 59, Port Elizabeth, 6000
Docex 12, Port Elizabeth

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"B"

Warren Parker (Director)

From: Marais, Wanda <WMarais@srk.co.za>
Sent: 28 April 2016 01:01 PM
To: Warren Parker (Director)
Subject: RE: Proposed 132 kV Powerline, Walmer, Port Elizabeth

Hi Warren,

Just to let you know that I have forwarded your queries to the project engineers and I am hoping to have answers for you very shortly.

Kind Regards

Wanda

"C"

From: Marais, Wanda [mailto:WMarais@srk.co.za]
Sent: 05 May 2016 12:50 PM
To: Warren Parker (Director)
Subject: FW: Proposed 132 kV Powerline, Walmer, Port Elizabeth
Importance: High

Hi Warren,

I have added in the information requested for you below for your ease of reference.

Kind Regards

Wanda

From: Warren Parker (Director) [mailto:wp@jgs.co.za]
Sent: 19 April 2016 11:32 AM
To: Marais, Wanda
Subject: Proposed 132 kV Powerline, Walmer, Port Elizabeth
Importance: High

Joubert Galpin Searle

Astute lawyers with business acumen
Commercial • Conveyancing • Labour • Litigation • Receivables

Dear Wanda,

I confirm my representation of Stylestar Properties 191 (Pty) Ltd.

I have received your Executive Summary and have also downloaded the draft report and annexures from your website.

The response to the suggestion by objectors that the electricity line be placed underground is *"The option of installing an underground cable for the entire route was eliminated during the design phase of the proposed development due to costs"*.

Could you please provide us with some clarity in this regard as it would assist us in formulating our clients comments to the draft assessment report:

1. When were the relative costs compared? 2010
2. Have the costs been revisited since then? Yes, material increases have been taken into account in the evaluation in 2014.
3. What are the exact costs of constructing an overhead line versus an underground line? It differs from terrain to terrain. On average a 132 kV overhead line is in the order of R550 000/km and an underground cable is R1.9 million/km.
4. Has any effort been made to source additional funding in respective of laying the line underground? The budget in the past financial years have been significantly reduced due to financial constraints facing the entire institution. Getting additional funding for this exercise is not possible as the overhead line is the suitable option both practically and financially.
5. How could the alternative of laying the cable underground be eliminated prior to receiving comments on the proposal? The best practical solution was considered.

I look forward to hearing from you in this regard.

Kind regards

WARREN PARKER
Director

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173 Cape Road, Mill Park, Port Elizabeth PO Box 59, Port Elizabeth, 6000
Docex 12, Port Elizabeth

" D "

Warren Parker (Director)

From: Warren Parker (Director)
Sent: 17 May 2016 09:24 AM
To: wmarais@srk.co.za
Subject: Proposed 132 kV Powerline, Walmer, Port Elizaberth

Importance: High

Joubert Galpin Searle

Dear Wanda,

As you know I represent Stylestar Porperties 191 (Pty) Ltd.

I have also been approached by Capeco to assist them in submitting comment to the draft assessment report in relation to the proposed powerline.

These comments are required by 18 May 2016.

We have previously suggested (by way of email dated 11 May 2016) that the information furnished to us by you in relation to the relative cost of constructing the powerline underground as opposed to above ground, be circulated to all interest parties and that the date for the submission of comments be extended.

We have also requested the paperwork which supports the costs provided to us.

As the comments submission deadline is tomorrow, we urgently request that you confirm that the deadline be extended.

We are still not in possession of the information requested from you and which directly impacts on the comments our clients intend to submit.

Kind regards

WARREN PARKER
Director

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173 Cape Road, Mill Park, Port Elizabeth PO Box 59, Port Elizabeth, 6000
Docex 12, Port Elizabeth

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"E"

NATIONAL ENERGY REGULATOR OF SOUTH AFRICA

Guideline on Minimum Information Requirements for Electricity Tariff Applications

Version 1

30 August 2010

TABLES OF CONTENTS

1 Introduction

1.1 List of Acronyms

1. BS - Balance Sheet
2. CAC - Centrally Administered Costs
3. CF - Cash Flow
4. CPI - Consumer Price Index
5. D-Form - Distribution Information Form
6. IS - Income statement
7. LIS - Licensee Information System
8. MIRTA - Minimum Information Requirements for Electricity Tariff Applications
9. OCGT - Open Cycle Gas Turbine
10. PPA - Power Purchase Agreement
11. R&D - Research and Development
12. RAB - Regulatory Asset Base
13. RRM - Regulatory Reporting Manual
14. RRS - Regulatory Reporting System
15. SRE - Statement of Retained Earning
16. WACC - Weighted Average Cost of Capital

1.2 Preamble

Recognising that the Energy Regulator has decided as follows:

NERSA will issue minimum information requirements that will provide clarity on needed information for tariff applications and act as guidance to the applicant as to the type of information required by NERSA for tariff determination and decision making; and

Pursuant to Sections 4(a)(ii), 14(1)(b), 15 and 35 of the Electricity Regulation Act, 2006 (Act No. 40 of 2006) as amended;

The following minimum information requirements for tariff applications are prescribed.

1.3 Purpose

The purpose of this document is to set out the minimum information requirements for the submission of tariff applications by regulated entities in the electricity supply industry.

The aim of the minimum information requirements is to provide applicants licensed by NERSA with an outline of the information to be provided when submitting a tariff application for approval by the Energy Regulator. The minimum information requirements apply to the following licensed activities, namely, generation, transmission, and distribution (wires and trading) respectively for each licensed activity..

The Energy Regulator will consider any tariff application complete if it meets all applicable minimum information requirements. Tariff applications that do not meet the minimum information requirements will be referred back to the applicant within two weeks of receipt by NERSA of such an application.

1.4 Regulatory Functions of NERSA

The National Energy Regulator of South Africa (NERSA) regulates the energy sector, which includes the petroleum pipeline, piped gas and electricity supply industries, in South Africa. In regulating the electricity industry, NERSA derives its powers and functions in terms of the Electricity Regulation Act, 2006 (Act No. 40 of 2006) (as amended) (hereinafter referred to as "the ERA"). The ERA confers upon NERSA the powers and duty to regulate electricity prices and tariffs. In particular, section 4(a)(ii) of the afore-mentioned Act states that "*the Regulator must regulate prices and tariffs*". In addition, section 14(1)(b) of ERA stipulates that the Regulator may make any licence subject to conditions relating to the furnishing of information and details to the Energy Regulator for the purposes of the administration of the afore-mentioned Act. This includes any information submitted to the Energy Regulator in consideration of tariff proposals by licensees in the electricity supply industry, including Generators, Transmitters and Distributors of electricity. Any information furnished to NERSA relating to price and tariff proposals will be considered by the Energy Regulator on the basis that it is complete and factual to facilitate proper analysis and approval of the proposed prices and tariffs.

In order to ensure that proper analysis and approval of tariff applications is achieved, NERSA requires correct and complete information on which the tariffs are to be based (or determined). To this end, a need for consistent and quality information has been identified. The required information for tariff analysis and approval includes both qualitative and quantitative data and must be in a form that is consistent with NERSA's objectives insofar as tariff principles are concerned and as stipulated in the ERA.

1.5 Legislative Mandate to Prescribe Information Requirements

NERSA is mandated by the ERA to regulate the electricity industry in South Africa. In terms of section 4 of the ERA, NERSA is empowered and has a duty to regulate prices and tariffs in the electricity industry in South Africa.

Section 35 (1) of ERA allows the Energy Regulator to make guidelines relating to any ancillary or administrative matter appropriate for the proper implementation of the Act. Section 35 (2) refers to the contents of the guidelines. Furthermore, section 14 (1) (b) of the ERA also allows NERSA to prescribe licence conditions that may include, *inter alia*, furnishing the Energy Regulator with information to perform its functions; the setting and approval of prices, charges, rates and tariffs charged by licensees; and the regulation of licensees' revenues.

1.6 Confidential Information

It is the duty of the applicant to bring to the attention of the Energy Regulator all information that must be treated as confidential in the application. However, the decision to grant such confidentially treatment remains the prerogative of the Energy Regulator. The Energy Regulator will be guided by the relevant legislation. In this regard, the following section of the Promotion of Access to Information Act (Act No. 2 of 2000) (hereinafter referred to as "the PAIA") will be considered:

Section 36(1) of the PAIA states that: "*Subject to subsection (2), the information officer of a public body must refuse a request for access to a record of a body if the record contains – trade secrets of a third party; financial, commercial, scientific or technical information, other than trade secrets, of a third party, the disclosure of which would be likely to cause harm to the commercial or financial interests of that third party; or Information supplied in confidence by a third party the disclosure of which could reasonably be expected- to put that third party at a disadvantage in contractual or other negotiations; or to prejudice that third party in commercial competition.*"

The Energy Regulator may take any measure or make any order that it considers necessary to ensure confidentiality, after satisfying itself that the request for confidentiality meets the condition as set out in the PAIA.

For administrative ease, financial information that NERSA has determined to be confidential in the Balance Sheet and Income Statement along with the detailed supporting schedules (BS1 to BS15 and IS1 to IS16) has been marked as such on the schedules. Licensees should then apply when making additional confidentiality requests in accordance with the provisions of PAIA.

1.7 Applicability of (Licensees Using) MIRTA

The MIRTA are to be used by all the licensees. However, NERSA has taken account of the various levels of preparedness of licensees to be able to comply with the MIRTA and also the regulatory methodology/framework in place and provides as follows:-

- Licensees that have implemented RRM will use the MIRTA in full immediately
- Licensees that have not implemented RRM will, on an interim basis, submit their tariff applications with all information required in this MIRTA but on a "lighter version". The lighter version requires all the narratives/explanations specified in this MIRTA guideline, but the financial information will only be the:-
    - General Financial Information
    - Balance Sheet (BS), Income Statement (IS), Cash-Flow Statement (CF); Sales Revenues (IS1) and Cost of Sales (IS2)
- Municipalities, other than Metropolitan Municipalities, will also use the lighter version and continue to use the D-Forms format to submit the supporting regulatory financial information until they have completed their respective implementations of RRM

The timeframes and transition from current tariff application and reporting formats to the full convergence between MIRTA and RRM along with the supporting technology systems are illustrated in **Section 2.1** below.

1.8 Disclaimer

Inclusion of any item in the prescribed MIRTA does not necessarily imply NERSA's acceptance of any expenditure, revenues or procedure, for tariff setting purpose, suggested by the use of such MIRTA. Furthermore, it must be noted that the NERSA reserves the prerogative to request further information and detailed explanation on any of the line items specified in MIRTA that is contained in a tariff application.

2 General MIRTA Preparation and Submission Requirements

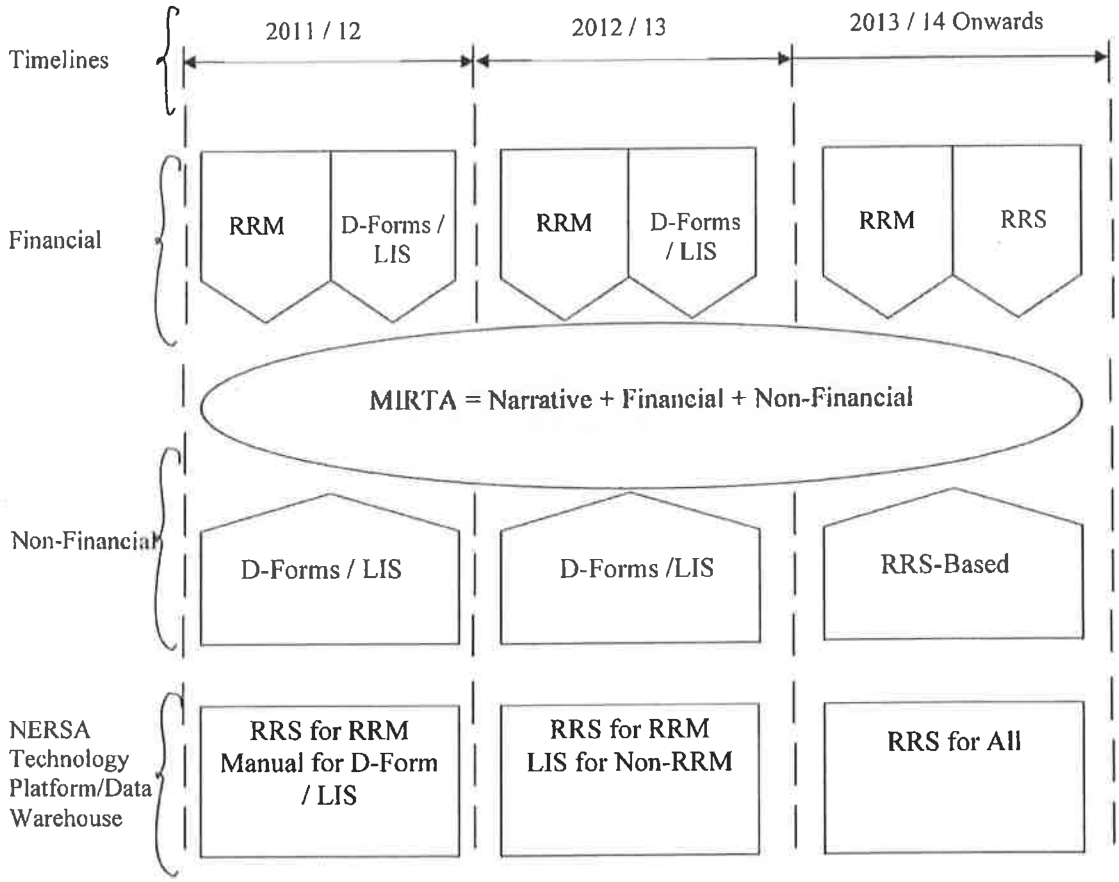
2.1 The elements of MIRTA and linkage to RRM/D-Forms

The information required for a tariff application must include the following:-

- Checklist
- General Requirements, Narratives and Explanations
- Financial Information
    - General Financial Information
    - Financial Information Specific to the Tariff Application
- Non-Financial Information

The following diagram shows the MIRTA and its linkages to the RRM/D-Forms

Linkage between RRMs, D-Forms and MIRTA



Explanatory Notes:

1) Financial refers to financial information as in RRMs and D-Forms.

2) NERSA Technology Platform/Data Warehouse refers to system available to receive and store licensee information submitted to NERSA.

3) Non-Financial refers to non-financial information from licensees.

4) Timelines refer to period adopted for a particular system.

2011/ 12	RRM and D-Forms as the RRS is being developed and LIS being rolled out.
2012/13	RRM & LIS as manual D-Forms are phased out. LIS captures electronically all information on current manual D-Forms.
2013/14+	RRS for All. The LIS will be migrated into RRS, hence information will be captured in the RRS. Light version will also be uploaded to the RRS electronically.

2.1.1 Checklist

The applicant must use the check list provided in the appendix to ensure completeness of the application. The checklist shows each section of this document against the corresponding relevant supporting financial information schedules to be submitted by the applicant.

(Submit Checklist)

2.1.2 General Requirements, Narratives and Explanations

Any tariff application submitted to the Energy Regulator for consideration and/or approval must include, or make reference to, the following:

- High level summary of the application;
- The applicant's shareholder compact;
- A statement (or status of the application) detailing the basis for the application;
- Corporate or organisational structure;
- All costs and revenues to be disaggregated into regulated business; non-regulated business; and corporate entity;
- Regulated business to be further disaggregated into electricity business and non-electricity business;
- Distribution business to provide separation in terms of retail and wires business; where possible
- A statement on assumptions (economic; financial; social; volumes; etc) taken into account in preparing the application;
- An explanation to all the data (amounts; statistics and volumes) and assumptions supporting the application;
- Statement on the treatment of affiliate businesses and related parties (if any);
- Statement on the split of costs and revenues between regulated and non-regulated;
- All data (amounts and volumes) must be submitted electronically in MS Excel format; and
- All other documentation submitted must be in MS Word format, with a PDF submission being the official tariff application submission.

2.1.3 Financial Information

2.1.3.1 General Financial Information

The following information must be submitted together with the tariff application:

- Segmented and consolidated Audited Annual Financial Statements (including, Income Statement; Balance Sheet; Statement of Retained Earnings; Cash Flow Statement) for the latest reporting period;
- Auditor's Report;
- Reconciliation statement between the annual financial statements and the financial information in the application;
- Any other information considered by the applicant material in supporting the tariff application; and
- Municipalities to submit financial information as reflected in the budgets approved by their respective Councils.

For details on structure and form of financial information, the respective applicants are referred either to the Instructions on the Minimum Information Requirements' Templates or the Guideline for Distribution Forms (Templates), whichever is applicable.

2.1.3.2 Financial Information in relation to the Application

The application line items must show (contain) two year historical financial information and at least five year forecast over and beyond the tariff period, covering information for the following:

- The previous financial year (actual audited figures);
- The year in which the application is made (projections);
- The three year period for which the application is made (forecasts); and
- The two year period succeeding the control period (forecast or plan).

Where possible, the financial information must be reflective of the prescribed tariff methodology applicable to the applicant.

The applicant must, where applicable or required by Government Policy or Directive, also provide the Energy Regulator with an indicative multi-year price path and supporting basis for its determination or estimation of the price path in accordance with the Electricity Pricing Policy (EPP)[1] or any other applicable policy.

For a municipality, other than Metropolitan municipalities, the financial information should cover the year in which the tariff is applicable and at least a two year forecast budget similar to the requirement prescribed by Section 17(1) (c)2 of the Municipal Finance Management Act (No. 56 of 2003).

The applicant must provide Pro-forma IS, Pro-forma BS; Pro-forma CF covering the tariff period under consideration

(Submit BS, IS, CF and SRE)

3 Specific Minimum Information Requirements

The following information requirements are applicable to the indicated categories of the tariff application.

3.1 Regulatory Assets Base

3.1.1 Explanation of the Regulatory Asset Base

3.1.1.1 Asset Values

The applicant must provide the Regulatory Assets Base (RAB) with the following details:

[1] The Electricity Pricing Policy issued in Government Gazette No. 1398 of 19 December 2008.

[2] Section 17(1)(c)states that *"an annual budget of a municipality must be a schedule in the prescribed format setting out indicative revenue per revenue source and projected expenditure by vote for the two financial years following the budget year"*.

- Asset values, by asset class, reflecting the Indexed Historical Cost;
- Asset values, by asset class, reflecting replacement cost. The basis for the determination of the replacement cost must be fully explained and demonstrated;
- Asset values, by asset class, as above should be fully disaggregated according to regulated business (Generation, Transmission and/or Distribution);
- Asset values for those asset funded from grants and/or customer contributions; and
- Estimated useful lives for each of the respective asset classes above.

The applicant is required to submit a statement on the assumptions made under each method indicated above and all the calculations done in determining the assets values under each method.

A written explanation on the variances in the regulatory asset base as a result of phasing-in of new assets and addition of capital under construction must accompany the tariff application. Variances of 10% or more in each asset category must be explained.

(Submit BS 1, BS3, BS11, BS12, BS13 and BS15)

3.1.1.2 Capital Expenditure

The applicant must provide the following information:

- Overall summary of capital expenditure per asset class over the tariff period showing the actual capital spend; assets (work) under construction; assets transferred to commercial operation; abandoned; transferred to mothballed.
- Explain and provide values for capital work under construction to show how it is to be phased-in to the regulatory asset base.
- Summarised scope; capital costs (in value and phasing-in); expected starting, finishing and commissioning dates; of all major projects, and where possible, all projects must be grouped and / or separated to reflect the total capital plan;
- At a minimum, a ten year forecast of the capital expenditure programme per asset class and per major project.

- Detailed explanation and justification for the drivers for capital expenditure variances (increases and decreases) for the control period.
- Detailed explanation on the approach followed for the planning and prioritisation of capital projects.
- Provide calculation and assumptions for allowance for funds used during construction to be capitalised.

Where possible, municipalities, other than Metropolitan municipalities, to provide details of planned capital electricity business expenditure as detailed in the Integrated Development Plan (IDP) or capital budgets.

(Submit BS14; and for municipalities other than Metropolitan Municipalities, D-Form Guideline)

3.1.1.3 Asset disposals and impairments

The applicant must provide the following information:

- List of assets disposed and/or decommissioned together with the reasons for such disposal and/or decommissioning; and
- Revenue or loss generated/incurred during the disposal.

The applicant should state and show how the loss/gain is treated in accordance with provisions of the Energy Regulatory e.g., if allowed by Energy Regulator, then should be treated as Regulatory Asset or Regulatory Liability allocated to Income Statement (tariffs) over a specified time period.

(Submit BS1 & 3, and IS 12)

3.1.1.4 Depreciation (for Current Period and Accumulated)

The applicant must provide the following information, applicable to both historic and replacement cost basis:

- Current depreciation amount included in the application.

- Accumulated depreciation to date for the RAB by each of the asset classes and by electricity business, per division, where applicable.
- Current depreciation method applied and any proposed changes to the depreciation policy which may impact on calculated depreciation values. This must also include a summarised copy of any asset condition (maintenance) study undertaken to prolong the economic life of assets.

(Submit BS2 and IS 9)

3.1.1.5 Working Capital

The applicant must provide the following information, on determination of its working capital requirements to cover its daily cash expenditure requirements to sustain ongoing operations of the utility:-

- Method of calculation of working capital; and
- Amount required.

(Submit BS4 and BS9)

3.1.1.6 Deferred Debits and Deferred Credits

The applicant must provide the following information:-

- detailing the origin of these balances
- amounts and period over which they will be released/charged to the Income Statement

(Submit BS5 and BS10)

3.2 Cost of Capital

This section is applicable to applicants that are required to apply the cost of capital for the purpose of a tariff determination as prescribed in the applicable tariff methodology or framework.

3.2.1 Explanation of Cost of Capital

The application must include a detailed explanation of the cost of capital reported in the application. The information to be included must, amongst others, make mention of the assumptions made in the calculation of each element of the cost of capital; the parameters used to calculate each element of the cost of capital; and the methodology used.

The applicant must provide the following information relating to cost of capital:-

- Notes on the funding model for new/planned CAPEX; assumptions and implications on the applicant's capital structure and cost of capital.
- Cost of Capital Study undertaken, if any, showing comparative cost of capital awarded decisions in other regulatory jurisdictions on a like-basis with the application (i.e., in real or nominal terms);

3.2.2 Cost of Debt

The applicant is required to submit:-

- A detailed explanation of the reported cost of debt, together with the parameters used; the calculation of the cost of debt; and the assumptions for the basis of calculation; and
- Report from various rating agencies regarding the applicant's rating which may impact on the cost of debt capital.

3.2.3 Cost Equity

The applicant must provide the following information relating to the cost of equity:

- Calculations and assumptions made in the calculation of cost of equity;
- Motivation for the cost of equity used in the application;

3.2.4 Capital Structure and WACC

The applicant is required to provide:-

- A full disclosure of its capital structure together with the assumptions made. Indicate in each year impact of new/planned CAPEX and funding model on the capital structure
- Calculation of the weighted average cost of capital (WACC);

(Submit BS 7, 8 & 9 and WACC Calculation)

3.3 Sales Revenues and Demand Forecasts

Details on the following must accompany the application:

- Sales revenue (billed revenue) for the following categories:
  - Standard tariff revenue by customer class;
  - Special Pricing Agreement (s) revenues per agreement;
  - Net export revenues;
  - Sales between regulated and non-regulated business; and
  - Sales separated between regulated and non-regulated business.
- Sales volume in MWh for each for the above categories.
- Projected sales to support the ten year forward-looking price path as per EPP.
- Energy demand forecast:
  - The energy wheel[3] with all the details on energy demand; supply; imports; export; losses, own use and sales; and.
  - The wheel must include the expected Transmission and Distribution line losses to meet the expected demand and should be projected for a period of five years to form the basis of the five year production plan.

(Submit IS 1)

3.4 Cost of Sales

3.4.1 Distribution Power Purchases Cost and Network Services

This section is applicable to the distribution section of the electricity business and to municipalities acting as distributors of electricity. The applicants are required to report fully the cost of energy purchases for sale from all generation sources, energy losses, including distribution and transmission networks charges and self generation[4].

(Submit IS 2 for Distribution)

---

[3] Balanced energy flow that reconciles power production and power purchases with power sales.
[4] Generation by the entity that owns the electricity distribution business.

3.4.2 Transmission Ancillary Services Costs and Energy Losses

This section is applicable to the Transmission section of the electricity business. The applicants are required to report fully the cost of energy losses and ancillary service.

(Submit IS 2 for Transmission)

3.4.3 Generation: Primary Energy Costs and Network Services

3.4.3.1 Primary Energy Cost

This section applies to those applicants that are engaged in the generation[5] of electricity and therefore require primary energy sources. In cases where the applicant uses a mixture of primary energy sources for generation of electricity, the various sources of primary energy must be indicated in the application. Further, in relation to Section 3.4.1 on Purchase Costs, municipalities engaged in self-generation activities are required to submit all the primary energy cost information relating to their self-generation activity.

It is recognised that primary energy costs (mainly relating to coal purchases, fuel, water and transport costs) represent the single biggest operating expenditure cost item in the generation of electricity. For this reason, it is important that any cost information, relating to primary energy, submitted for tariff setting purposes is as accurate as possible and includes those costs that were prudently and efficiently incurred. To this end, the Energy Regulator requires information on primary energy costs to be presented in a manner that enables it to perform a rigorous analysis of the costs incurred. This will assist the Energy Regulator to ensure that any tariff setting process takes into account all the relevant information. The envisaged form and manner of presentation of primary energy costs will include details on the following:

---

[5] Generation includes self-generation by municipalities.

3.4.3.2 Coal Fired Power Stations

3.4.3.2.1 Coal Purchased and Burnt

- Aggregate coal purchases; volumes; price per ton; and costs per contract type;
- A breakdown of coal purchases; volumes; price per ton; and costs per contract type for each power station;
- Motivation for having purchased coal on the spot market or plans to utilise the spot market; and measures to ensure these purchases will not be applicable for a period exceeding twelve (12) months;;
- Transport costs:
    - to be reported as a separate line item for each coal contract type for each power station;
    - provide a detailed explanation for any large and unexpected increases and strategies to control such increases; and
    - the strategies must go beyond the tariff period and the costs identified separately.
- Assumptions and summary of indices used for cost escalations and the applicable rates;
- The total aggregate production output (in MWh) of coal-fired power stations in total and the production output of each power station;
- A statement on the quality of coal burned (calorific value of coal in MJ/kg), and different burn rates (kg coal per kWh produced) per coal-fired power station;
- Total average calorific vale for each coal contract type;
- Projected aggregate coal purchases, including price; volume; quality and burn rate for ten year period envisaged in the EPP, and a breakdown for each power station;
- Detailed explanation and justification for increases and decrease in costs per coal contract type in each power station; and
- Stockpile levels and values per power station with planned changes over the tariff period.

3.4.3.2.2 Other Primary Energy Costs at Coal Fired Power Stations

- Aggregate water purchase cost and volume
- Water treatment cost

- Start up fuel oil and gas cost and volume
- Coal handling cost

3.4.3.3 Other Primary Energy Sources

(OCGT; Hydropower; Nuclear; Non-Applicant's Generation; etc)

This section is applicable to applicants engaged in the generation of electricity utilising other forms of primary energy sources. All other sources must be separately indicated, including volumes and associated costs, at least to the same level of detail as 3.4.3.2.1 above where applicable. At a minimum, the applicant must provide the following information in relation to the following types of primary energy sources utilised:

3.4.3.3.1 Open Cycle Gas Turbines

Information relating to OCGTs must, at a minimum, include the following details:

- The assumptions made on the costs of fuel;
- The costs assumed;
- Comprehensive reasons on the changes to the cost from year to year;
- Plan and reasons for use of this power generation option;
- Risk mitigation strategies undertaken by the generator and the assumptions made;
- Volume output anticipated; and
- OCGT utilisation plan.

3.4.3.3.2 Hydropower and Nuclear

The applicant is required to submit the following information:

- The production plans for each primary energy source;
- The costs and output for each primary energy source; and
- Unit cost per kWh produced for sale.

3.4.3.3.3 Non-Applicant's Generation (IPP)

Information relating to non- applicant's generation including the Independent Power Producer's must include the following details:

- The volumes to be purchased for the tariff period;
- The associated costs;
- Detail of signed Power Purchase Agreements (PPAs) of the existing contracts;
- Amendments to the existing PPA's and the reasons thereof; and
- A plan on the PPA's to be entered into during the control period.

(Submit IS2 for Generation)

3.5 Operation Expenses

3.5.1 Operating Expenditure

Information in this category must include the following expenditures:-

- Operational expenses
- Customer account expenses
- Sales expenses
- Load Settlement expenses
- Regulatory Debits/Credits charged or released to income
- Taxes for regulated income other than income/corporate income taxes[6]:

Information relating to all these operating expenditures must be reflected in the following manner:

- The expenditure must **exclude** expenditure on ongoing business that is capital in nature such as those for refurbishments and those that prolong the economic useful lives of assets. These are capitalised expenses.
- All costs related to operating expenditure are to be disaggregated according to electricity business and non-electricity business; and corporate entity, where applicable;

[6] Corporate income taxes are excluded because the WACC is calculated pre-tax

- Electricity business to be further disaggregated into: generation; transmission, and distribution (wires and trading), as applicable;
- Normal[7] and abnormal[8] costs to be clearly indicated;
- Different cost categories to be clearly indicated;
- Explanation and justification on the assumptions for proposed cost escalations and projections;
- Explanation and justification on key cost drivers relating to each category of operating expenditure; and
- An analysis of the variances in actual incurred costs and previous projections.

(Submit IS3, IS4, IS5, IS6, IS7, IS10 and IS11)

3.5.2 Manpower Costs[9]

The tariff application must be accompanied by the following information:

- All manpower costs must be disaggregated according to the electricity business (Generation, Transmission, and/or Distribution) and non-electricity business;
- All manpower costs must be submitted, including costs relating to salaries; overtime; pension benefit costs; bonuses; and medical costs;
- Central executive management manpower costs allocated to the electricity business (Generation, Transmission, and/or Distribution, whichever is applicable) must be itemised separately;
- Provide headcount of manpower in the different electricity business (Generation, Transmission, Distribution, whichever is applicable) as is possible to determine trends in average cost per employee; and
- Explanation and justification for the proposed percentage increase in manpower costs.

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[7] Normal costs refer to costs incurred for the day-to-day business operations.
[8] Abnormal costs refer to those costs that are event driven and occur infrequently.
[9] Manpower Costs also refers to human resource or personnel costs.

- Manpower costs that are capitalised and linked to capital expenditure projects should be shown seperately.

(Submit IS3 to IS6 which includes labour directly charged to the utility business, IS 7 for shared labour costs, reconcile to and submit the total in IS 13, and for Municipalities, other than Metropolitan municipalities, D – Form Guideline)

3.5.3 Repairs and Maintenance

The applicant is required to provide information on all costs related to repairs and maintenance as separate line items for labour, materials and supplies and other expenses, and also provide an explanation and justification for any increases in these costs.

These costs must **exclude** expenditure on ongoing business for refurbishments and those that prolong the economic useful lives of assets which must be capitalised.
A schedule of planned repairs and maintenance together with anticipated power disruptions must be included in the application.

(Submit IS 3, and for Municipalities, other than Metropolitan municipalities, refer to the Guideline for D-Forms)

3.5.4 Debtors

Details on the following must accompany the application:

- Outstanding debt by customer class;
- Provision for bad debts;
- Age analysis;
- Amount of debt written-off;
- Basis of provisioning for debtors impairments; and
- Any mitigation measures to recover debt and associated costs.

(Refer to RRM account#904.1 and submit in IS4 and BS 4; and Municipalities, other than Metropolitan Municipalities, refer to the Guideline for D - Forms)

3.5.5 Centrally Administered / Shared cost

It is recognised that centrally administered costs/charges (CAC) include both corporate overheads and other costs/charges that cannot be directly linked to any one division/department of the electricity entity, such as for example, Generation, Transmission and Distribution. In this regard, the applicant is required to provide the following information in relation to centrally administered or shared costs:

- All centrally administered costs / shared costs must be clearly defined and identified;
- An explanation and justification of the transfer of costs and/or revenues between divisions together with the reasons for the transfer;
- A statement on all cost items within centrally administered or shared costs increasing above the Consumer Price Index (CPI) – should be motivated for and state the impacts if these were capped at CPI; and

An explanation for allocation drivers and percentage split or allocation of shared services to the different divisions of the regulated business and non-regulated business.

(Submit to IS 7)

3.5.6 Demand Side Management (DSM)

The applicant must provide the following information in relation to demand side management:

- DSM strategy; plan and programs covering the entire control period;
- The proposed budget for DSM over the control period;
- DSM costs;
- Explanation and justification for increases in DSM costs; and
- All costs to be itemised separately.

(Refer to RRM account# 909 and Submit in IS5 of Distribution Template)

3.5.7 Other Costs

All costs covered under the label "Other" must be disaggregated and specified to the lowest line item level for each of the licensed activity. The following materiality thresholds must be used as a guide in providing details in cost items under "Other":

- All cost items increasing at 5 percentage points above inflation must be itemised separately;
- All cost items equivalent (in Rand terms) to 10% of the total "Other" category must be explained and itemised separately; and
- All new items should be indicated clearly and reasons provided for adding them to this category.

3.6 System Losses

The applicant is required to report and quantify all system losses (both technical and non-technical) at Transmission and Distribution level or where applicable to the specific business of the applicant; indicate the costs associated with such losses; and the proposed mitigation measures to minimise the losses.

(Included in IS1 and IS2)

3.7 Research and Development Costs

Research and development activities are necessary to improve the effectiveness and efficiency of the activities and functions of a particular entity. Any research and development activities should at best be aimed at improving the quality of services provided to customers and improving the efficiency of the regulated entity's operations. In this regard, the applicant is required to submit the following information relating the research and development activities:

- Research and development strategy and plan;
- Planned research and development activities and their impact on the operations of the applicant;

- Research and development costs;
- An explanation of variances between planned and actual cost for research and development; and
- All costs must be itemised separately.

4 Environmental Levy

This section is applicable to those applicants that are engaged in the generation of electricity and to whom the Government Environmental Levy[10] applies. Applicants to whom the levy is passed-through as a cost also need to report that cost as a separate line item. The applicant must provide the following information in relation to the Government imposed 2c/kWh environmental levy:

- Methodology adopted in the implementation of the environmental levy; and
- Costs and revenues must be separated from the regulated costs and revenues, i.e. the applicant must ring–fence and itemise separately the costs and the revenues, depending on the treatment of the incidence of the levy on the applicant, associated with the levy.

(Included in IS1 and IS2)

5 Required Revenue Summary

The applicant must provide summary of all information and calculations relating to the Required Revenue as per the application for each regulated activity. Furthermore, applicants are required to provide the full revenue to be recovered from the tariff (different customer categories). This summary must include the following:-

- Regulatory Asset Base (RAB) on which a return is calculated
- The % Rate of Return Applied on the RAB;
- Total Required Revenues made up of:

[10] Environmental Levy as imposed by National Treasury.

1. Total Return on RAB
2. Return of Capital (Depreciation for the period separately from amortization of indexation/inflation write-up)
3. Primary Energy and/or Power Purchased
4. Environmental Levy
5. Total Operating Expenses required
6. Repairs and Maintenance Expenses required
7. R&D
8. Unusual events - Gains/Losses on Disposition of Regulated Plant
9. etc

(Submit Required Revenue Summary)

6 Tariff Structure

6.1 Distribution Tariffs

Since the revenues applied for by the electricity distribution applicant are recovered through the retail tariffs, it is therefore important for the following information to accompany the electricity distribution (wires and trading) application:

- Assumptions made for each tariff category together with expected volumes, c/kWh increase and revenues on the standard retail tariffs;
- Reconciliation statement of the volumes and revenues used to calculate the retail rates to the volumes and revenues used in the application;
- The tariff model used to calculate the resultant retail rates;
- The details of the tariff structure and impact of the proposed structure on customers; and
- Where applicable, submit the tariff structure in the prescribed format, such as Inclining Block Tariff structure.

6.2 Transmission Tariffs

The revenues applied for by the Transmission Network Service provider are recovered through a wholesale transmission service tariff. It is important for the assumptions made by the transmitter to charge its cost out to the relevant generators, traders and distributors are required.

6.3 Generation Tariffs

Since the revenues applied for by generators are recovered through a wholesale energy sales tariff that applies to relevant electricity distributors, the assumptions made by the generator to charge its cost out to the relevant distributors are required.

(Submit IS 1 and Applicant's own Tariff Structures)

7 Appendix

The applicant must include all tables and templates containing all the data and information (figures) in the appendices section of the application.

The following Templates are indicated as Appendices a- l.

- Check list
- BS
- IS
- CF
- SRE
- BS1 to BS 15
- IS1 to IS 16
- Notes
- WACC Calculations
- Required Revenue Summary
- Tariffs Proposed

"F"

COST OF SUPPLY FRAMEWORK

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ABBREVIATIONS AND ACRONYMS

Ave LF	Average Load Factor
Ave PF	Average Power Factor
A&E	Average & Excess
A&G	Administrative and General Expenses
APP	Average Purchase Price
c/kWh	Cent per kilowatt-hour
CAD	Cost Allocation Diagram
COS	Cost of Supply
Dx	Distribution
EPP	Electricity Pricing Policy
GND	General Network Diagram
Gx	Generation
HV	High Voltage
IPP	Independent Power Producer
kVA	Kilovolt-Amps
kWh	Kilowatt-hour
LV	Low Voltage
MTS	Main Transmission Substation
MV	Medium Voltage
MWh	Megawatt-hour
NERSA	National Energy Regulator
O&M	Operation and Maintenance Expenses
R/kVA	Rand per Kilovolt-Amps
R&M	Repairs and Maintenance
RND	Reduced Network Diagram
Tx	Transmission

EXECUTIVE SUMMARY

The National Energy Regulator (NERSA) is a regulatory authority established as a juristic person in Terms of Section 3 of the National Energy Regulator Act, 2004 (Act No. 40 of 2004). NERSA's mandate includes regulation of the electricity supply industry. According to Section 4(ii) of the Electricity Regulation Act, 2006 (Act No. 4 of 2006), the Energy Regulator must regulate electricity prices and tariffs.

Policy position 23 of the Electricity Pricing, 1998 (GG No. 31741 of 19 December 1998) ("the EPP") states that:

> *Electricity distributors shall undertake Cost of Supply (COS) studies at least every five years, but at least when significant licensee structure changes occur, such as in customer base, relationships between cost components and sales volumes. This must be done according to the approved National Energy Regulator of South Africa (NERSA or 'the Energy Regulator') standard to reflect changing costs and customer behaviour.*

In support of the above Acts, NERSA developed a COS Framework to be used by all licensed electricity distributors ('licensees') in South Africa. The framework will be used as a guideline to licensees when developing their COS studies.

A consultation paper on the COS Framework was published for written comments and a public hearing was held for further comments on the framework. NERSA considered all comments when developing the final COS Framework.

1 BACKGROUND

A Cost of Supply (COS) study is one of the most important considerations in establishing and designing electricity rates that are implemented to provide the service required by customers and recover costs incurred by licensees. The objective of COS study is to apportion all costs required to service customers among each customer class in a fair and equitable manner. The National Energy Regulator (NERSA) has developed the COS Framework in order to promote sustainability of the electricity supply industry while protecting customers against unduly high prices.

2 SCOPE

The framework is meant to assist all licensed electricity distributors in performing their cost of supply studies.

The COS Framework aims at assisting all licensees, with focus being placed on smaller licensees that have limited capacity and experience data base challenges. Licensees that have advanced capacity and data warehouses can expand the adopted approach to a level that will meet their specific needs.

The framework primarily focuses on the distribution business of a licensee, nonetheless, it is also acknowledged that certain distributors also have own generation plants and others have/might progress into transmission capacity. Therefore, the framework includes cost drivers relating to generation, distribution and transmission of electricity.

The framework follows a four-step process. The steps cover revenue requirement, cost functionalisation, cost classification and cost allocation with an ultimate goal of rate setting.

The framework serves as a regulatory standard that will guide licensees to develop their individual COS studies and submit them to the Energy Regulator for consideration. All licensees are required to submit their COS studies to the Energy Regulator.

3 DEVELOPMENT OF THE COS FRAMEWORK

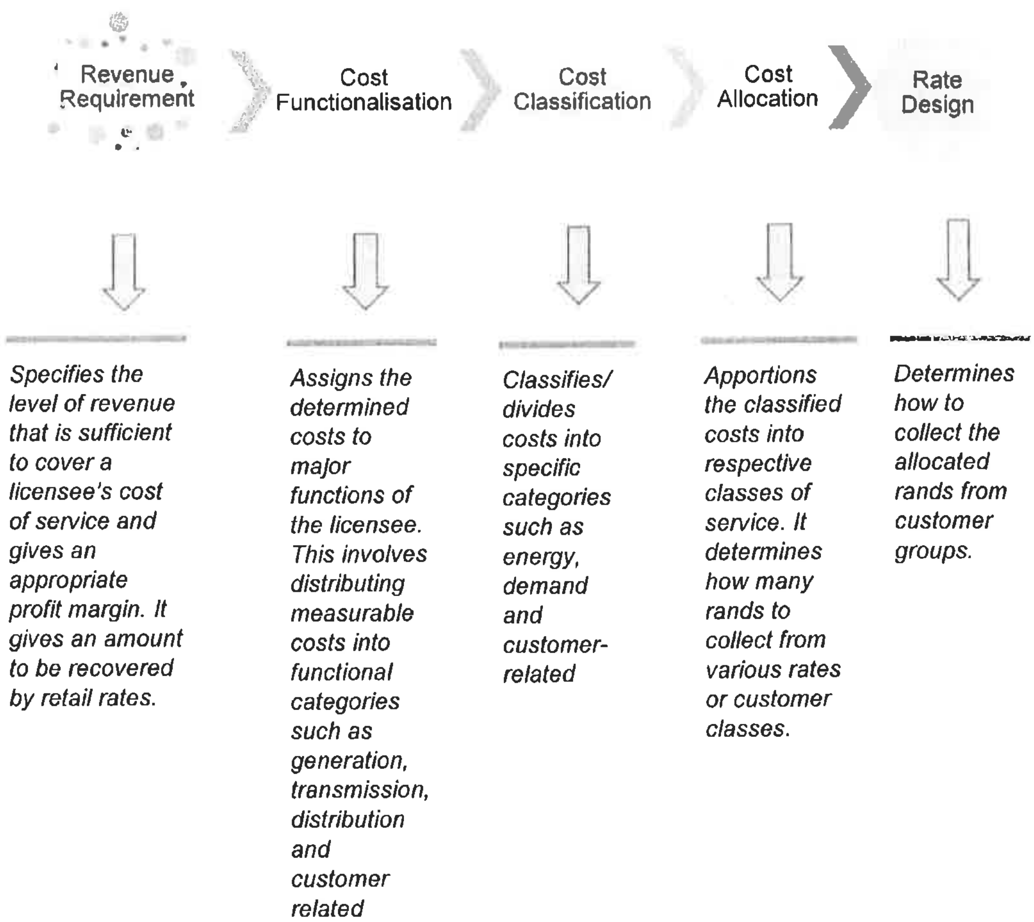
3.1 Approach followed in developing the Framework

The approach that was followed in developing the COS Framework includes desktop research, examining presentations and papers, as well as attendance of relevant workshops that looked into existing approaches to COS studies. Discussions were also held with stakeholders and relevant legislations in the field of COS were was also considered. After careful analysis and consideration of the above, an approach that closely relates to the environment for licensees in South Africa was adopted.

3.2 The adopted approach towards COS Framework

The Embedded Cost Basis was adopted in the development of COS Framework in South Africa. This approach determines the apportionment of accounting-based revenue requirement using the functionalisation, classification and allocation processes with the ultimate goal of rate setting. Figure 1 below depicts the steps of the adopted approach, which will be discussed in detail in the paper.

Figure 1: COS Steps



3.2.1 Cost of Supply Steps

3.2.1.1 Revenue Requirement

A licensee, in order to remain viable, must be given the opportunity to recover its total costs incurred in providing electricity services, plus a reasonable margin. The revenue requirement of a licensee is the total cost to supply electricity to all customer categories plus a margin as determined by the Energy Regulator. Section 2.2 of the Electricity Pricing, 1998 (GG No. 31741 of 19 December 1998) ("the EPP") states:

> *In the absence of competition, regulators may select from a range of methodologies to regulate the industry. All these options have some advantages and disadvantages. Regardless of the method of regulation or price formation it is essential that an efficient and prudent licensee should be able to generate sufficient revenues that would allow it to operate as a viable concern now and in the future.*

It is under this premise that NERSA has explored numerous options available to determine licensees' revenue requirements; these methods include rate of return, price cap, revenue cap, yard stick regulation and benchmarking approach.

After careful consideration of the above methods, NERSA decided not to adopt any of them, as they are not practical in the environment of licensees due to various challenges that include, among others:

- difficulty of implementation where accounting and property records are poor as is the case with most licensees;
- assuming that all licensees are operating under the same perfect conditions;
- providing weak incentives for licensees to operate efficiently;
- possibility of lowering licensees' service levels; and
- limiting competitiveness.

Policy Position 1 of the EPP states:

> *The revenue requirement for a regulated licensee must be set at a level which covers the full cost of production, including a reasonable risk adjusted margin or return on appropriate asset values...*

In support of the above policy position, NERSA adopted the Cost Plus Methodology as an interim methodology for implementation by licensees, including small licensees with limited capacity and database challenges. It should be noted that the Cost Plus Methodology can be too basic and limiting to well established licensees that have advanced capacity and data warehouses. Licensees are encouraged to start keeping records and building databases and capacity in preparation for the progressive revenue requirement methodology. The Cost Plus Methodology is discussed in detail below.

a) *Cost Plus Methodology – the adopted revenue requirement approach*

This methodology determines the revenue requirement by allowing the licensee to recover the total cost to supply electricity, including a reasonable margin that is represented by a percentage surplus. The Cost Plus Methodology is made up of various cost components plus a reasonable profit margin, as indicated in Table 1 and discussed in detail below:

- purchases [this includes purchases from Eskom, Independent Power Producers (IPPs), own generation and other sources];
- operating costs;
- repairs and maintenance;
- depreciation/amortisation of refurbishment and capital costs;
- interest on loans; and
- shared costs.

Table 1: Approach to the Cost Plus Methodology

Total Required Purchases (MWh)				
(a) Sales forecast (Expected sales to customers)				X
(b) Electricity purchased for own use[1]				X
(c) Street lighting				X
(d) = (a) + (b) + (c) Total sales forecast				X
(e) Allowable loss factor (Represents a percentage energy loss of 10%)[2]				**1.10**
(f) = (d) x (e) Required purchases				**XX**
Sources of Electricity Purchases	**(g)** Volume (MWh)	**(h)** Weight (%)	**(i)= (j) / (g)** Average Purchase Price(c/kWh)	**(j) = (g) x (i)** Total Cost (R)
Purchases from Eskom				X
Purchases from IPPs				X
Own Generation				X
Purchases - Other options				X
Total		**100%**		**XX**

[1] This refers to consumption by electricity department
[2] The tolerable range is 5% - 12%

Add other costs	
Operating expenditure	X
Shared costs	X
Depreciation/amortisation of refurbishment and capital costs	X
Interest on loans	X
(k) Total costs before Repairs and Maintenance (R&M) costs	XX
(l) = (k) x 6% Repairs and Maintenance costs at 6% of total costs before R&M	X
(m) = (k) + (l) Total costs before surplus	XX
(n) = (m) + 15% Add surplus allowable	15%
(o) = (m) + (n) **Total Allowable Revenue**	XXX
(p) = (o) / (f) Average selling price	X
(q) Previous year price	X
(w) = (p) / (q)-1 x100 Average percentage price increase	X %

i. <u>*Purchases*</u>

This takes into account purchases from Eskom, IPPs, other sources and own generation. The licensee should use the purchases for the test period to forecast sales for the financial year that it is applying for. The forecast purchases should include street lighting electricity, own use electricity and the allowable loss factor. The allowable loss factor is defined as 10% of total anticipated purchases (refer to Table 1 above). This represents a 10% energy loss as per current NERSA benchmarks. The tolerable range for energy losses is 5-12%. Licensee that have an efficient system can reduce losses to below 10%. Licensees will be incentivised for losses below 10%.

The forecast purchases are weighed against the percentage contribution of each source of electricity to arrive at the average purchase price (APP) and consequently, the total purchase cost of a licensee.

ii. <u>*Operational expenditure*</u>

- The licensee will be allowed operational expenditure in line with the following principles:
  - Allowable expenses relate to all expenses that are incurred in the production and supply of electricity. These costs include normal

operating expenditures such as manpower or labour costs and overheads (centrally administrative and general expenses allocated) that are normally recovered within one financial year, but excludes refurbishment costs that must be capitalised.

- Expenses must be incurred in the normal operations and supply of electricity.
- Expenses must be prudently and efficiently incurred and must be at arm's length transaction. Licensees must have a competitive procurement policy and demonstrate to the Energy Regulator that it has been strictly adhered to in its procurement processes.
- For any expenses incurred under abnormal or extraordinary circumstances, consideration shall be given to spreading such expenses over a number of years. This consideration may also apply to particular types of expenditure within management's control only for purposes of tariff smoothing, once the Energy Regulator is satisfied that those expenses have been prudently and efficiently incurred.
- Allowance for the human resources costs will be at reasonable levels. The Energy Regulator may require access to wage settlement documents to verify the reasonability of these costs. Costs relating to corporate social investment, expenses on charitable donations and broad social development activities cannot be included as qualifying (regulated) expenses unless it can be shown that these costs benefit tariff-paying customers.
- Other expenses that are not related to the core business of supplying electricity will also be disallowed.

Note: In classifying operating costs further into controllable or non-controllable elements, the Energy Regulator will decide on incentives to the licensee to minimise costs that are under its control, as well as encourage it to reduce some of the costs that are not under its control.

iii. *Shared Costs*

Shared cost should be limited on the basis of usage or causation by the licensee or electricity department. Costs that contain characteristics of different cost drivers must be classified and allocated according to their characteristics.

iv. *Depreciation*

- Depreciation shall be based on the straight line method of depreciation and on the expected useful life of the assets.

- NERSA will determine and publish the useful life of various assets of licensees.
- Refurbishment costs shall be capitalised and amortised over the expected useful and economic lives of the refurbished assets.

v. <u>*Repairs and maintenance*</u>

A minimum of 6% of total cost (before profit margin) will be allowed for repairs and maintenance. Repairs and maintenance expenditure exceeding 6% will be assessed on a case-by-case basis by the Energy Regulator.

vi. <u>*Margin*</u>

After total costs have been ascertained, the revenue requirement will be determined by adding a profit margin. The margin is represented by the surplus to be earned by the licensee. The surplus is determined by the Energy Regulator after taking into account the peculiar circumstances of each licensee. Currently, the Energy Regulator uses a tolerable range of 10-20% and a target of 15% on the percentage surplus.

Note: In cases where a licensee does not have sufficient resources to deal with internal challenges, the licensee must develop a comprehensive plan demonstrating the inability to address these challenges and apply to the Energy Regulator. Should there be funds awarded for corrective measures, such funds should be ring-fenced and reported on.

3.2.1.2 Cost Functionalisation

Cost functionalisation entails the arrangement of costs according to major operating functions of a licensee, such as production/generation, transmission, distribution or customer-related costs. This assists in facilitating a determination in terms of which customer groups are responsible for such costs. All costs should be assigned to the major functions of a licensee. Costs can be assigned to different functions within a licensee as shown in Table 2 below.

Table 2: Cost Functionalisation

Function	Activity/Cost
Generation (Gx)	relates to all costs that are involved in the generation of power.
Transmission (Tx) [3]	includes all costs associated with the transfer of power from one geographical location to another within a system.

[3] This accommodates licensees that might progress into transmission capacity

Distribution (Dx)	relates to the transfer of power from the transmission system through the distribution system to consumers.
Customer-Related Cost	relates to number and type of customers served.

a) Importance of Cost Functionalisation

Cost functionalisation is critical for determining efficient rates. It also paves a way for the next steps, which are cost classification and allocation. Functionalisation requires the licensee's accounting records to be kept according to a uniform system of accounts, based on the adopted system. The costs are recorded in specific accounts or sub-accounts.

b) Practical approach to Cost Functionalisation

Most of a licensee's costs can be directly assigned to relevant functions. However, certain costs, such as shared costs, cannot be assigned to specific functions. Nonetheless, they should be allocated. Straight forward costs should be assigned and allocated to a relevant function of the licensee, namely generation, transmission, distribution and customer-related, as depicted by a practical example in Table 3 below.

Table 3: Approach to cost functionalisation (a practical example)

Cost	Gx	Tx	Dx	Customer-Related
Underground conductors			X	
Transmission lines		X		
Fuel costs	X			
Admin salaries				X
Collection Agency Fee				X

3.2.1.3 Cost Classification

After a licensee's revenue requirement is separated by function, the next step is to classify costs into cost components. The objective of cost classification is to arrange costs into groups that bear a relationship to a measurable cost-defining characteristic of rendering the service.

Cost classification is a two-step process. First, functionalised costs are classified as either fixed or variable costs. Next, fixed and variable costs are classified as demand, usage or energy and customer-related. The sum of these three types of costs within a given class is the cost to serve that class.

a) *Process of cost classification between fixed and variable cost*

Firstly, functionalised costs are classified as either fixed or variable costs, depending on their characteristics. Fixed costs are costs that remain constant regardless of the volume of output and are predominately associated with capital investment. Fixed costs include investment-related costs such as return, taxes, as well as certain Operation and Maintenance (O&M) expenses, including labour and Administrative & General (A&G) expenses.

Variable costs are costs which vary with the volume of output. Variable costs primarily consist of fuel costs. The non-labour portion of certain O&M expense accounts can also be classified as variable costs. Non-labour costs include materials and supplies.

b) *Process of cost classification between Energy, Demand and Customer-Related Costs*

After functionalised costs are classified as fixed or variable, they are then classified as energy, demand or customer-related as indicated in Table 4. The energy and demand components are generally associated with providing peak and annual services (refer to Table 4). Variable costs are classified to the energy component in order to match their recovery with the level of output.

Table 4: Cost Drivers

Cost Driver	Characteristics
Demand	Triggered by peak demands and fixed in nature
Energy	Vary with volume of energy increased
Customer-Related Cost	Depend on number and type of consumer served

The energy-related classification consists of those expenses that vary with changes in the unit consumption of kilowatt-hours (kWh), such as purchased power or energy charges. The energy-related classification also consists of costs that are associated with the supply of energy to meet the electricity requirement of the licensee.

Demand costs are associated with meeting the system output and demand requirements or peak demand of each customer and overall peak of a licensee.

Demand classification relates to providing capacity to serve portions or all of the system load requirements.

Certain distribution plant accounts and associated operation and maintenance charges are classified as jointly demand and customer-related. These are expenses that are incurred to provide service to a customer and are also expected to meet customer peak demand requirements. As an example, the number of poles and transformers in a licensee's system varies, in part with the number of customers served by the utility. These items also represent capacity on the utility system available to meet peak demand requirements. Thus they exhibit attributes of both demand and customer charges. The customer component of joint related accounts is that portion of expense that varies with the number of customers.

The customer-related classification is directly related to each electricity user and varies by the number and type of customers served. Customer-related classification consists of those expenses that vary with the number of customers served and volume of energy sold. Customer costs are associated with billing functions, accounting and other expenses that are necessary to connect new customers to the system and serve the licensee's customers. These costs typically vary by the type of customer served, with large industrial customers being the most expensive group of users to connect to the system.

Table 5 below shows how different costs that have been assigned to different functions can be classified:

Table 5: Cost functions and classification

Function	Cost classification
Gx	Demand-Related Energy-Related
Tx	Demand-Related
Dx	Demand-Related Consumer-Related

The above costs vary by the type of customer served. The sum of the demand, energy and customer-related costs within a given class is the cost to serve that class.

3.2.1.4 Cost Allocation

Cost allocation apportions the classified costs into respective classes of service. It sets out an approach that a licensee should follow to allocate costs to different customer categories when it undertakes COS studies.

a) Cost Allocation Methodology

The adopted methodology for cost allocation is the asset valuation methodology. This methodology accurately reflects the replacement value of a licensee's assets. It uses annualised replacement costs and therefore is a closer approximation of the true economic cost of providing the service.

This methodology allows for cost chain involved in the supply of electricity to be understood. The function of the cost chain ranges from the production of electricity, transmission of produced energy over power lines to load centres, transportation and transformation of the power over the distribution networks, delivering the energy to the end-users, providing support services to such end-users, and the billing of end users.

The adopted approach limits cost allocation to the following cost drivers: energy-driven costs (in monetary units, c/kWh), demand-driven costs (R/kVA) and customer driven costs (R/customer).

There are various factors that influence the costs of providing electricity to customers and they vary depending on, among others, the quantity of electricity used, the size of supply required, the period when electricity is used, the geographic location of the customer, the voltage at which supply is provided and the power factor.

i. <u>*Energy cost allocation*</u>

The energy cost component of a licensee consists of costs that would vary with changes in the unit consumption of energy. The energy cost component of purchases is easy to allocate because the purchase rates can simply be passed on to all lower voltage levels with an additional adjustment for losses.

The losses are determined by assuming loss factors for each network component and then comparing the cumulative losses to a network position with the expected loss values for that particular network location. If the cumulative losses of the network components do not compare with the expected or theoretical losses, the loss factor of every network component should be scaled accordingly. The share of total cost attributable to a customer group is calculated as follows:

- calculate the time-differentiated consumption (if required) of every customer group at each voltage level; and
- multiply the consumption by the loss differentiated purchase rates.

The result of this allocation is a Rand value for each customer group at each voltage level representing the energy purchase cost.

Additional costs such as overheads and other energy-related costs can be incorporated with the calculated (energy-related) unit costs. These costs can be applied to specific customers. The total cost must be divided by the total energy consumption for agricultural customers to derive a unit energy-related cost for each customer in the category. This derived unit cost must be added to the unit purchase cost for each agricultural customer.

The total energy-related cost for each agricultural customer can now be determined by multiplying the unit energy-related cost (including the additional energy-related costs) with the total consumption of the customer.

ii. *Demand cost allocation*

The demand cost allocation method is used for all costs that are classified as being demand-driven. This includes the network capital cost, the operations and maintenance cost of some networks, demand purchase cost and the wires component of the purchase cost (if applicable). For the purpose of this framework, the Average and Excess (A&E) method is adopted under demand cost allocation. The A&E method is used to allocate the cost of each asset category in the Reduced Network Diagram (RND) to each applicable customer group (refer to Appendix A for illustration). If a customer group uses a specific asset, that customer group should be included in the allocation of the cost of the asset group. The cost of the 132kV assets, for example, will be determined based on the demand imposed by each customer group on the 132kV network and the cost of these assets.

The allocation of a share of the network capital to a specific customer group is then calculated as follows:

- calculate the proportion of each asset category in the RND that should be allocated to each customer group;
- sum all cost portions for all applicable assets per customer group; and
- divide the total cost by the sum of the customer groups' undiversified maximum demands to calculate a R/kVA cost.

iii. *Customer costs allocation*

Customer costs vary by the type of customer served. The number of customers or weighted number of customers is the basis for the customer allocation factors.

The total cost of a function is divided by either the number of customers or the weighted number of customers triggering such a cost component. The number of large customers, for example, is used to divide the cost of meter reading for large customers.

The customer service cost, for example is divided by the weighted customer numbers to determine the unit cost per customer. The principle is that one large customer is equivalent to several small customers. Therefore, a bigger proportion of the cost is allocated to the large customer.

b) Cost allocation process

The process of cost allocation involves allocation along cost drivers for:

- energy cost driver, which relates to kWh consumed plus the network technical losses;
- transmission network, which relates to diversified network demand as measured at main transmission sub-station;
- distribution network, which refers to the network maximum demand relative to the system demand; and
- retail/customer-related, which relates to the point of delivery share of total retail costs differentiated by the type of service and customer demand size.

i. <u>Phase 1</u>

The first phase of the process of cost allocation involves conducting of the following activities in order to arrive at the Cost Allocation Diagram (CAD):

- Conducting a network cost of supply study. The study is achieved by conducting a bay-by-bay study.
- Derivation of the General Network Diagram (GND). This is achieved by reviewing the network topography and obtaining the network lines and transformation assets and capacity details.
- Determining distribution assets per replacement value using overnight cost. This is achieved by using the network data obtained to cost each asset category per voltage level, i.e. high voltage (HV), medium voltage (MV), and low voltage (LV). Thereafter LV supplies should be analysed by making assumptions and cost LV. Once the information is analysed, it must then be summarised and captured in relevant templates.
- Derivation of the CAD. This is the last step, which will be achieved by consolidating the GND and replacement costs (or overnight costs) into the CAD.

ii. *Phase 2*

The second phase of the process involves costing information, which is achieved by conducting the following activities:

- revenue requirement per licensee will be achieved by effecting the approved revenue for licensee.
- purchase tariffs will be achieved by determining energy rates and by the distribution network charges and zonal loss factors.
- updating the distribution network loss factors.
- conducting an electricity sales forecast.
- determining the customer categories.

iii. *Phase 3*

The third phase of the process involves cost allocation, which is achieved by conducting the following activities:

- Active energy and technical losses. The cost of electrical losses is unbundled and recovered as a function of (a) the appropriate loss factors for the relevant voltage level, whether urban or rural and (b) distribution cost of energy purchases cost on a time-of-use basis. Since the purchase rates are currently differentiated according to the time of use, the measurements and calculations of losses will follow the same time-of-use periods. In calculating the cost of these losses for customers, both transmission and distribution loss factors are considered in allocating the costs, as follows:

Table 6: Loss factors

Cost for total losses **= $\sum$\{Delivered energy$_t$ x (distribution loss factor$_{VU/R}$ x transmission loss factor$_Z$-1) x P$_t$\}** **Where:** **VU/R = at the relevant voltage level and urban/rural differentiation and** **Z= transmission zone and** **t = the appropriate Peak, Standard or Off - peak (PSO) time period and** **P$_t$= Purchase energy price for each PSO time period.**

- Transmission loss factors are geographically differentiated, whereas the Distribution loss factors are based on estimated average losses per voltage category – the voltage level and rural and urban networks are differentiation as indicated in Table 7 below.

Table 7: Distribution loss factors per voltage category

Voltage	Urban Loss Factor	Rural Loss Factor
<500V	1.0912	1.1189
≥500V - <66kV	1.0560	1.0900
≥66 – ≤132 kV	1.0174	NA
> 132 kV	0.0000	NA

The geographical position of a supply point has an impact on electrical losses, i.e. the further the point of supply is from the source of the supply, the higher the losses. As losses are a cost to the business, they are allocated to customer categories based on the amount of losses determined. Losses over urban and rural networks are different and therefore loss factors are associated with different geographic positions. Therefore voltage also has an impact on losses.

- Distribution network. The principle cost drivers for the network business are the voltage at which customers receive supply, the location of the customer and the capacity of the supply. Distribution network costs are therefore allocated according to Distribution's current voltage level and geographic categories on a R/kVA basis. The geographic (local and density signal) is provided through rural and urban differentiation. The voltage differentiation is based on the following categories.

Table 8: Voltage level categories

VOLTAGE Urban	VOLTAGE Rural
< 500 V	< 500 V
≥ 500 V and < 66 kV	≥ 500 V and < 66 kV
≥ 66 kV and ≤ 132 kV	
> 132 kV	

Network costs are allocated at each voltage level using the average and excess statistical method. This method takes into account the impact of a customer's capacity on average on the network, plus any peak impact. Diversity is therefore considered when allocating the costs.

The density of customers also has an impact on distribution cost per connection, i.e. the greater the density, the lower the cost per connection. Therefore costs are differentiated into rural and urban networks. This will ensure that costs are allocated correctly.

- Retail service. This includes the costs associated with marketing, meter reading, billing, and direct customer services and corporate overheads. The abovementioned costs are allocated per customer as the total cost divided by the number or weighted average number of customer categories imposing that cost component. These costs are allocated based on the capacity of the customer split between administration and service-related costs into the categories as shown in the table below:

Table 9: Retail cost categories

Small	$\leq$ 100 kVA
Medium	>100 kVA and $\leq$ 500 kVA
Large	>500 kVA and $\leq$ 1 MVA
Very Large	> 1 MVA
Key Customers	As per qualification criteria

3.2.1.5 Rate Setting

Once all costs have been allocated to customer classes, they are translated into unit rates. Rates are designed to recover the jurisdictional cost of service. While taking into account the cost incurred in serving a particular class of customers, the below principles are also considered in rate setting.

a) Principles of rate setting

When formulating a tariff methodology, a number of key principles and or objectives must be considered. These principles represent the often conflicting requirements of different stakeholders and inform the analysis and decisions around the most appropriate regulatory options and detailed pricing approaches adopted.

Table 10: Principles and objectives of rate setting

Stakeholder	Tariff objective	Description
Licensee	Cost reflective	All prudently incurred cost should be recovered and yield reasonable profit
	Encourage efficient use	Appropriate price signals that will encourage efficiency
	Implementation cost	Implementation costs should be low

Customer	Affordability	Price will exclude inefficiency (energy losses)
	Predictable and stable	The customer should be able to forecast future tariffs
	Transparent	Easy to read and apply, with no hidden costs

- *Cost Reflectivity*

  To ensure long-term viability of the industry, regulators typically permit the regulated entities to set prices that generate sufficient revenue to cover total costs. This is the amount that is determined and required to produce energy, maintain and develop its networks, serve customers, and to provide a reasonable profit. Tariffs that are set below the true cost of supply are arguably the greatest hindrance to a viable, sustainable and growing power sector that is able to consistently meet customer demand and provide reliable supply.

- *Promotion of Efficient Use*

  Pricing is a tool to encourage customers to constrain their consumption or to encourage them to take up services that are less costly to deliver. There should be price signals to customers to which they react according to their level of 'economic rationality'.

- *Affordability*

  It is widely accepted that affordability stands out as one of the fundamental requirements of electricity pricing in developing countries. Electricity has the potential to improve quality of life by bringing convenience and dignity to the ordinary household, while unlocking the potential for a wider array of business activities. However, affordability does not necessarily mean a very low price of electricity.

  The process of generating, transporting and delivering electricity has associated costs and these need to reflect in the price of the product to send the correct consumption signals to customers. In order for the electricity supply industry to be sustainable, average tariff levels must reflect the cost of supply and should, as far as possible, exclude inefficiencies. Affordability may, nonetheless, necessitate clearly identified subsidies or cross-subsidies targeted towards specific consumers.

* *Predictability & Stability*

  Customers make long-term investment decisions based on the projection of long-term electricity prices. There is thus an obligation on the part of the electricity supply industry to communicate anticipated price trends to the industry. An effective tariff communication plan will:
  - inform customers of future price trends in the industry;
  - keep the licensees and customers informed regarding future tariff structure adjustments;
  - provide clear indications of the tariff application and approval processes;
  - promote confidence within the customers and potential investors; and
  - announce price increases in advance so that customers can prepare for the impact.

* *Transparency*

  Tariff schedules should be easy to read, understand and interpret, with no embedded or hidden costs. Tariff transparency enhances customer confidence in the fairness of tariff levels. In seeking transparency in tariffs, there should be no components on the customer invoice that are not presented on the official tariff schedule. Tariff structures in a regulated environment should be kept simple. Unnecessarily complex tariff structures needlessly increase the administrative burden and push up the cost of providing electricity.

b) Tariff Components/Principal Cost Categories

There are three principal cost categories in the electricity supply industry that have a bearing on tariff structure namely:

* costs that vary with customer numbers and service intensity (R/month);
* costs that vary with capacity/demand (kVA); and
* costs that vary with energy (kWh).

The basic principle to be employed by the regulated entity in structuring tariffs should be to seek optimal cost-reflectivity by retaining the principal cost categories as tariff components and mapping the respective costs to them.

c) Rate Design Methodology

After all the costs plus a reasonable profit margin are allocated to different customer classes. The required revenue will be broken into demand-related charge (R/kVA), customer-related charge (R/month) and energy-related charge (c/kWh) in line with the principles and formulas contained in the South African Distribution Tariff Code.

The End

Marais, Wanda

From: van Wyngaardt, Eugene <vanwyng@vwsa.co.za>
Sent: 11 August 2016 07:51 AM
To: Marais, Wanda; Ward8 NMMM; Safety & Security Cllr - Rautenbach
Cc: mdupreez@elliespe.co.za; cecil@falcon.co.za; mandy.elliott@imp.co.za; sclegg@oldmutual.com; karel.steyn@gmail.com; chrisgagiano@gmail.com; leonminnie@mweb.co.za; Reid, Mark; jvanschalkwyk@hatch.co.za; Van Wyngaardt, Charmaine (CVanWyngaardt@hatch.co.za); therese.swart@za.pwc.com; flipa@gmail.com; petra@goldlaw.co.za; renaud@webmail.co.za
Subject: RE: "Proposed 132kV Powerline, Macon Road, Lorraine"
Attachments: ATT00001.txt; ATT00002.htm

Hi Wanda,

I would just like to follow up on the status of this project with the regards to changing from overhead to underground for the section along Macon Road. Refering to the petition by all bordering residents.

Futhermore, I would also like to give you an update on the current stormwater system that is being laid i.e. the existing trench, as mentioned below. This job has been delayed due to the "discovery" of no less than 4 powerlines that are crisscrossing the path of the stormwater system. Apparently they are now going to alter the routing of these existing powerlines. AGAIN, SURELY THE 132KV PROJECT SHOULD TIE UP WITH WHAT IS GOING ON THERE AT THE MOMENT, THERE IS MONEY AND TIME TO BE SAVED!!!!!!!

Regards

Eugene

Afternoon Eugene,

I confirm that Mrs Grey and Mrs Patton have been added to our database. Thank you for the information.

With regard to your concern in respect of the existing trench, the query will be forwarded to the project team along with the other IAP queries to be addressed. It will also appear, along with the appropriate response, in the Post-Application Draft Basic Assessment Report which will also be opened up to public comment in due course.

Kind Regards

Wanda

From: van Wyngaardt, Eugene [mailto:vanwyng@vwsa.co.za]
Sent: 10 May 2016 10:10 AM
To: Marais, Wanda; Ward8 NMMM; Safety & Security Cllr - Rautenbach

Cc: mdupreez@elliespe.co.za; cecil@falcon.co.za; mandy.elliott@imp.co.za; sclegg@oldmutual.com; karel.steyn@gmail.com; chrisgagiano@gmail.com; leonminnie@mweb.co.za; Reid, Mark; jvanschalkwyk@hatch.co.za; Van Wyngaardt, Charmaine (CVanWyngaardt@hatch.co.za); therese.swart@za.pwc.com; flipa@gmail.com; petra@goldlaw.co.za; renaud@webmail.co.za
Subject: RE: "Proposed 132kV Powerline, Macon Road, Lorraine"

Good Morning Wanda,

In response to the below. Thank you for the registration of the residents.

I can confirm that, 293 Macon – Lorna Peters, 297 Macon – Helen Gray and 299 Macon – Mrs J Patton, DO NOT HAVE e-mail.

Furthermore, in response to the RESPONSE in the "Executive Summary" with regards to laying the cable underground along Macon road. The response stated "NOT FINANCIALLY FEASABLE".

Are they aware that currently a 3m deep trench is available as they are laying stromwater pipes. Surely with the correct planning the same trench can be utilized for the cables ???

Regards

Eugene van Wyngaardt (295 Macon – 041 994 4373)

From: Marais, Wanda [mailto:WMarais@srk.co.za]
Sent: 05 May 2016 11:52 AM
To: van Wyngaardt, Eugene; Ward8 NMMM; Safety & Security Cllr - Rautenbach
Cc: mdupreez@elliespe.co.za; cecil@falcon.co.za; mandy.elliott@imp.co.za; sclegg@oldmutual.com; karel.steyn@gmail.com; chrisgagiano@gmail.com; leonminnie@mweb.co.za; Reid, Mark; jvanschalkwyk@hatch.co.za; Van Wyngaardt, Charmaine (CVanWyngaardt@hatch.co.za); therese.swart@za.pwc.com; flipa@gmail.com; petra@goldlaw.co.za; renaud@webmail.co.za
Subject: RE: "Proposed 132kV Powerline, Macon Road, Lorraine"

Dear Eugene,

I acknowledge receipt of your email and the petition attached. Apologies for the delay in responding as I have been on sick leave.

I am in the process of adding every person who submits a comment (such as each of the signatories) to our database so I can forward them all future notifications regarding the project. The easiest and quickest way to correspond with IAPs is obviously by email and I see that in some instances no email address is included for a signatory. This means that all notifications must be sent to their street address by registered mail which can cause a delay in the receipt of the notices which is outside SRK's control. Persons already registered as IAPs have been excluded from the lists below.

The persons listed below have provided sufficient information for registration as an IAP, including email address. No further action is required at this stage:

- Michelle du Preez;
- Leon Minne;
- Mandy Elliott;
- Suzette Clegg;
- Mark Reid;
- Karel Steyn;
- Chris Gagiano
- Petra Alberts

The persons listed below have provided sufficient information for registration, but in the absence of an email or fax facility, all correspondence will be forwarded per registered mail. SRK does not accept any responsibility for the delay in receipt of IAP notices due to the postal system. IAPs on this list are encouraged to forward their email details to me so that they will receive instant notifications:

- Lorna Pieters;

The persons listed below have either provided insufficient or illegible contact information which prohibits registration. They are encouraged to forward their full contact details to me to allow registration to be effected:

- 285 Macon Rd - writing too feint – name and email address illegible
- 297 Macon Rd – Helen – incomplete name and insufficient contact information
- 299 Macon Rd – name illegible

Kind Regards

Wanda

From: van Wyngaardt, Eugene [mailto:vanwyng@vwsa.co.za]
Sent: 29 April 2016 09:00 AM
To: Ward8 NMMM; Safety & Security Cllr - Rautenbach; Marais, Wanda
Cc: mdupreez@elliespe.co.za; cecil@falcon.co.za; mandy.elliott@imp.co.za; sclegg@oldmutual.com; karel.steyn@gmail.com; chrisgagiano@gmail.com; leonminnie@mweb.co.za; Reid, Mark; jvanschalkwyk@hatch.co.za; Van Wyngaardt, Charmaine (CVanWyngaardt@hatch.co.za); therese.swart@za.pwc.com; flipa@gmail.com; petra@goldlaw.co.za; renaud@webmail.co.za
Subject: "Proposed 132kV Powerline, Macon Road, Lorraine"

Hi Wanda,

Please find herewith our signed petition against construction of the an overhead power line.

Please reply to this mail as acknowledgement that you have receive it and please advise of intended next steps.

Regards

Eugene van Wyngaardt - Resident

084 2234 789

From: van Wyngaardt, Eugene
Sent: 21 April 2016 11:07 AM
To: 'Ward8 NMMM'; Safety & Security Cllr - Rautenbach; 'Marais, Wanda'
Cc: 'mdupreez@elliespe.co.za'; 'cecil@falcon.co.za'; 'mandy.elliott@imp.co.za'; 'sclegg@oldmutual.com'; 'karel.steyn@gmail.com'; 'chrisgagiano@gmail.com'; 'leonminnie@mweb.co.za'; Reid, Mark; 'jvanschalkwyk@hatch.co.za'; Van Wyngaardt, Charmaine (CVanWyngaardt@hatch.co.za)
Subject: FW: FOKUS OP WYK 8 / FOCUS ON WARD 8 - 2016/04/20

Good Morning Wanda, Gustuv and residents/home owners of Macon Road.

After receiving this report yesterday, I realized that we are going to have to do a lot more to ensure the powerlines will go underground and not OVERHEAD, for section A to C (next to Macon road).

I started by walking from house to house along Macon road and was disappointed to find out that the homeowners knew little to nothing about this project.

Clearly by just dropping off fliers into the letter boxes was not a very effective means of informing everybody.

The responses, to the comments and objections made, was very poor. I got the impression that we are just not taken seriously. (See attached) For example, just my comments:

*Recommending that the existing underground conduit pipe be used or the huge stormwater pipe laying, currently taking place, be utilized. Their answer “not financially viable”. Seriously ? what I am recommending, is a cost saving !!!!

*This area is utilised by the public for recreational activities. Their answer, “ not clear what recreational activities are referred to”. They conveniently omitted my original comment which stated, photography, kite flying and horse riding.

*All the residents of Macon Road object to the overhead powerlines in front of our houses. Their answer “ no signed petition was included to confirm that all residents object”.

Futhermore, I herewith request that a visual illustration of what a 132kv overhead powerline structure looks like be forwarded to us.

The signed petition will be submitted tomorrow.

Regards

Eugene van Wyngaardt (local resident 295 Macon Road, Lorraine)

From: Ward8 NMMM [mailto:ward8@mandelametro.gov.za]
Sent: 20 April 2016 11:42 AM

To: Safety & Security Cllr - Rautenbach
Subject: RE: FOKUS OP WYK 8 / FOCUS ON WARD - 2016/04/20

Good morning Residents / Goeie more Inwoners

Please see attached e-mail for your information. / Sien asseblief aangehegde e-pos vir u inligting.

Regards / Groete

GUSTAV RAUTENBACH
DA COUNCILLOR : WARD 8
DA CAUCUS CHIEF WHIP: NMBM
DA SAFETY AND SECURITY SPOKESPERSON (NMBM)
079 490 0054 (CELL)
041 368 7008 (OFFICE)
(ao)